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PART III:

FEDERAL POWER COMMISSION

■

SALES OF NATURAL GAS

Opinion and Order Prescribing Uniform National Rate

Title 18—Conservation of Power and Water Resources

CHAPTER I—FEDERAL POWER COMMISSION

SUBCHAPTER A—GENERAL RULES

SUBCHAPTER E—REGULATIONS UNDER NATURAL GAS ACT

[Docket No. RM75-14; Opinion No. 770]

PART 2—GENERAL POLICY AND INTERPRETATIONS

PART 154—RATE SCHEDULES AND TARIFFS

Opinion and Order Prescribing Uniform National Rate for Sales of Natural Gas

JULY 27, 1976.

This proceeding was initiated to review the rates established in Docket No. R-389-B pursuant to 18 C.F.R. 2.56a(n) for the 1975-1976 biennium and to consider such changes in the rate structure prescribed in 18 C.F.R. 2.56a as may be required in the public interest. Based upon the evidence of record, we find that a new uniform national base rate for post-January 1, 1975 gas of $1.42 per Mcf, escalating one cent per quarter (equivalent to less than 3% per annum), subject to adjustment for Btu content, State or Federal production, severance, or similar taxes, and gathering allowances where applicable, is just and reasonable and is hereby adopted effective on the date of issuance of this order. This rate is fully cost-based and justified. Additionally, non-cost factors have been examined to ensure that the cost-based rate is just and reasonable.[1] This rate is applicable for (1) sales of natural gas made from wells commenced on or after January 1, 1975, and (2) sales made pursuant to contracts executed on or after January 1, 1975, for the sale of natural gas in interstate commerce where such gas has not previously been sold in interstate commerce.

We also find that a new uniform national base rate for 1973-1974 biennium gas of $1.01 per Mcf, subject to adjustment for Btu content, State or Federal production, severance, or similar taxes, and gathering allowances where applicable, is just and reasonable and is hereby adopted effective on the date of the issuance of this order. This rate is applicable for (1) sales of natural gas made from wells commenced on or after January 1, 1973, and prior to January 1, 1975, and (2) sales made pursuant to contracts initially executed on or after January 1, 1973, and prior to January 1, 1975, for the sale of natural gas in interstate commerce where such gas had not previously been sold in interstate commerce.

The Commission had previously established a single uniform national rate applicable to all producing areas for post-December 31, 1973, gas supplies for the 1973-1974 biennium in Docket No. R-389-B.[2] The Commission also established in Docket No. R-478,[3] as a companion to Docket No. R-389-B, just and reasonable rates for pre-January 1, 1973 natural gas supplies. The rates established herein update the rates established in Docket No. R-389-B pursuant to 18 C.F.R. 2.56a(n).

Contrary to the discussion of the biennial review in Opinion No. 699-H,[4] the gas which initially qualified for the rate prescribed by Opinion No. 699 will not be priced at the same level as the qualifying gas in the 1975-1976 biennium. However, a new rate reflecting updated costs, productivity and a different income tax treatment, is prescribed for sales of natural gas qualifying in Opinion No. 699-H under Section 2.56a(a)(2)(i) and (ii) of the Commission's Regulations. The rates prescribed herein do not apply to sales of natural gas made under new contracts, where prior contracts had expired of their own terms under which such gas had previously been dedicated to interstate commerce.

OUTLINE

I. Scope of the opinion.
II. Introduction to methodology.
  A. Production and development patterns.
  B. Operation of the OEC model.
III. The rate determination: Post-January 1, 1975.
  A. The timing of expenditures.
  B. Productivity.
  C. Drilling cost.
    1. Successful well cost.
    2. Dry hole cost.
  D. Other production facilities.
  E. Other exploration.
  F. Exploratory overhead.
  G. Lease acquisition.
  H. Recompletion and deeper drilling.
  I. Operating expenses and regulatory expenses.
  J. Working capital.
  K. Cost allocation to liquids.
  L. Depletion period.
  M. Rate of return.
  N. Federal income taxes.
  O. Royalty.
  P. Escalation.
  Q. Price determination.
    1. The 699-H model applied.
    2. The OEC model results.
IV. The rate determination for 1973-1974 vintage gas.
V. Non-cost factors.
  A. Intrastate market.
  B. Commodity value.
  C. Economic impacts.
  D. Other economic factors.
VI. Rate adjustments.
  A. Deeper drilling and deeper offshore water depths.
  B. Btu adjustment.
  C. Tax adjustments.
  D. Pipeline PGA filings.
  E. Refunds and rate reductions.
  F. Special relief.
  G. Gathering allowance.
  H. Small producers.
  I. Rates for Appalachian-Illinois area.
  J. Pipeline production.
VII. Environmental impact.
VIII. Conclusion.
  A. General conclusions.
  B. Additional comments.
Appendices
  A. Allocation of dry hole footage.
  B. Dry hole factors.
  C. Rate of return by industry group.
  D. Staff impact analysis.

I. SCOPE OF THE OPINION

A. OVERVIEW

We have determined that a rate of $1.42 per Mcf for qualifying post-January 1, 1975 gas and a rate of $1.01 per Mcf for qualifying 1973-1974 biennium gas is just and reasonable. These rates were derived from an analysis of many factors, including drilling productivity, drilling costs and all of the other costs associated with the production of natural gas. We also considered pursuant to recent court decisions, certain non-cost factors, including the price of competitive fuels, the impact upon supply and demand, inflationary pressures, the nation's natural gas shortage and conservation factors.

In computing the costs for the 1975-1976 biennium, we employ a discounted cash flow analysis by costing the averaging successful well that is drilled in the test year 1976. We also use an additional model to test and extend the validity of the 699-H methodology. A 15% rate of return is allowed on the investment necessary for the exploration and development of natural gas. We employ a depletion life of 15 years, with a pre-production period of 3 years. An income tax component is included in the costing model to reflect the tax reductions experienced in the pre-production years and the tax liability incurred in productive years.

Productivity, expressed in terms of annual non-associated gas reserves added divided by successful drilling footage, has declined significantly from that used in Opinion No. 699. Nineteen seventy-four successful well drilling costs were 14% greater than the trended values used in that opinion. The marginal income tax rate of 48% is used where none was used in Opinion No. 699. These factors account for the significant rate increase over that prescribed in Opinion No. 699-H.

In revising the rate prescribed in Opinion No. 699-H, we employ the same discounted cash flow analysis as used in that opinion with modification of four of the factors used therein. Drilling costs are changed to reflect the higher costs actually incurred during 1973 and 1974. The productivity range has been expanded from seven years (1966-1972) to nine years (1966-1974) to include the reported productivities for 1973 and 1974. The tax treatment has been altered to reflect the tax liability resulting from the repeal of the percentage depletion allowance.[5] The depletion life has also been changed from 18 to 15 years.

Since 1968, the annual consumption of natural gas has exceeded the annual addition of new reserves. Opinion No. 699-H was issued by the Commission to establish a uniform national rate with an underlying purpose of reversing the trend of diminishing dedications of new gas supplies to the interstate market. After

[1] The Supreme Court has previously held that both cost and non-cost factors must be considered in establishing a just and reasonable rate. Permian Basin Area Rate Cases, 390 U.S. 747 (1968), *Mobil Oil Corporation* v. *F.P.C.*, 417 U.S. 283 (1974).

[2] Just and Reasonable National Rates for Sales of Natural Gas From Wells Commenced On Or After January 1, 1973, And New Dedications Of Natural Gas To Interstate Commerce On Or After January 1, 1973, Opinion No. 699, et al.

[3] Just And Reasonable National Rates For Sales of Natural Gas From Wells Commenced Prior To January 1, 1973, Opinion No. 749, et al.

[4] See Opinion No. 699-H, ---- F.P.C. ----, slip opinion at 50.

[5] See Int. Rev. Code of 1954, § 613A(b)(2), added by the Tax Reduction Act of 1975, Pub. L. § 94-12, 501.

review of the actual dedications since the issuance of Opinion No. 699–H, we find that this purpose was not achieved. Total new qualifying gas flowing in interstate commerce is only slightly more than one and one-half trillion cubic feet per year at this time. This low level of new dedication is largely due to substantial cost increases in 1974, increases that could not have been predicted, and thus were not taken into account, in establishment of the rate prescribed in Opinion No. 699–H. Active intrastate markets with higher prices captured most new onshore gas.

The recognition of these cost increases in this proceeding will encourage the dedication of new reserves to the interstate market. The rates established herein will permit increased drilling activity and will place interstate pipelines in a more competitive position in the onshore markets.

We estimate that the immediate impact of pricing post-January 1, 1975 natural gas at $1.42 per Mcf and January 1, 1973 to December 31, 1974 natural gas at $1.01 per Mcf is to add about $1.5 billion to the consumer's cost for natural gas in the first year. Of this amount, approximately 55% goes to the Treasury in higher taxes, 25% compensates for higher costs, and 20% accrues to the producers. Over the longer run, we expect consumers will benefit as a result of reduced reliance on expensive alternate fuels. We believe that this decision will lead to increased gas supply and to greater gas conservation. It will make more gas available for residences and it will help to relieve the pressure of shortages on business and industrial consumers.

B. PROCEDURAL HISTORY

This proceeding was initiated December 4, 1974, with an Order Instituting National Rate Proceeding [6] issued pursuant to the Administrative Procedure Act [7] and the Natural Gas Act.[8] The Commission in that order did not propose any specific rates, terms or revisions to the rules prescribed in Section 2.56a, but stated that it would rely upon the responses filed in this proceeding by the various parties and the staff as the basis for modifying Section 2.56a. To assure the effective and expeditious resolution of these proceedings, all natural gas producers [9] with annual jurisdictional sales in excess of ten million Mcf and all interstate pipeline companies were made respondents to this proceeding. In addition, any interested person, including those persons named as respondents, desiring to participate in this proceeding, were required to file a notice of intention to participate by December 20, 1974.

The December 4, 1974, order initiating this proceeding was modified by notices issued on December 31, 1974, March 4, 1975, May 13, 1975, May 30, 1975, June 10, 1975, July 10, 1975, and July 25, 1975, extending the time for the filing of initial comments to August 11, 1975, and for the filing of reply comments to September 11, 1975.[10]

On June 13, 1975, in this docket the Commission issued an order instituting the "31-lease investigation" [11] to update a prior staff study [12] of offshore Louisiana gas reserves. The order required natural gas companies holding reserves in the subject fields to submit their respective reserve estimates to the Commission by July 25, 1975. Notice was issued on July 11, 1975, extending the time for such filings until July 31, 1975. On July 24 and August 4, 1975, the Commission issued orders denying a number of applications for rehearing of the June 13, 1975 order. Subsequently, a number of producers [13] filed petitions for review of the June 13 and July 24 orders in several courts of appeals. The cases were consolidated in the Court of Appeals for the Fifth Circuit, which denied a motion for a stay of the orders, but directed that the data submitted be kept in confidence. In the face of the court's confidentiality order, the Commission was unable to publish the base data obtained from the producers and seek public comment thereon, as it had originally intended. However, the Commission was able to complete its investigation by subpoena of data from the American Gas Association. On June 21, 1976, after notice to the parties, the Commission incorporated in the record in this proceeding a report by staff of its generalized conclusions from all data, believing the publication to be consistent with the court's confidentiality order. On July 2, 1976, the Court of Appeals entered its opinion, holding that the release of the base data obtained from the producers was within the power of the Commission, if an appropriate basis for release is established.[14] However, release of the base data is not presently contemplated, inasmuch as the purposes of the 31-lease investigation have been largely accomplished.

On June 16, 1975 in this docket, the Commission issued an order [15] inviting the views of the parties on the weight, if any, that should be given to current prices in intrastate natural gas market. The order required comments to be filed by July 24, 1975, and reply comments to be filed by August 15, 1975. By notice issued August 11, 1975, the time for filing comments was extended to September 5, 1975.

On August 4, 1975 in this docket, the Commission issued an order setting forth rate recommendations of the Bureau of Natural Gas (BNG) and the Office of Economics (OEC) and provided parties the opportunity to file comments in reply to staff's comments by September 5, 1975.[16] On October 3, 1975, in this docket, the Commission issued an order clarifying the rate recommendations made by OEC and provided parties a further opportunity to reply to OEC's response by November 3, 1975.[17] In addition to the aforementioned staff rate recommendations, the Pipeline and Producer Rates Division of the Bureau of Natural Gas also made rate recommendations. These were set forth in a Notice of Further Staff Rate Recommendations [18] after the commenting procedure had terminated. In this notice, the Commission provided parties another opportunity to file comments on these additional rate recommendations by April 23, 1976, with replies thereto to be filed by May 14, 1976.

Several complete prospective cost studies were filed by other parties to this proceeding. The United Distribution Companies (UDC) submitted a cost study dated May 14, 1975, that excluded from consideration Alaska, Appalachia, the Gulf of Mexico, and Texas Permian. Indicated Producer Respondents (IPR) submitted on May 30, 1975, a nationwide cost study. On July 24, 1975, UDC submitted estimated costs of natural gas from the Gulf of Mexico. All parties were given the opportunity to comment upon each of the cost studies and numerous reply and supplemental reply comments were received.

The recommended prices in the comments range from a high of $2.84 per Mcf [19] to a low of $.56 per Mcf.[20] The comments contain wide variation on all major elements of the estimated price, including methodology, productivity, well cost, and federal income tax. All of the cost studies were founded upon 1973 and earlier Joint Association Survey (JAS) cost data and 1974 and earlier American Gas Association (AGA) reserves data.

[6] 39 F.R. 43093, December 10, 1974.

[7] 60 Stat. 237, 918, 993 (1946); 61 Stat. 37, 201 (1947); 62 Stat. 99 (1948); 80 Stat. 250 (1966); 5 U.S.C. § 551, et seq. (1970).

[8] 52 Stat. 822, 823, 824, 825, 829, 830 (1938); 56 Stat. 83, 84 (1948); 61 Stat. 459 (1947); 76 Stat. 72 (1962); 15 U.S.C. §§ 717c, 717d, 717f, 717g, 717i, 717m, 717n, 717o (1970).

[9] The term "natural gas producer" is used to refer to all persons producing natural gas including pipeline companies having exploration and production departments. An "affiliated producer" is a natural gas producer that is affiliated with an interstate pipeline company. An "independent producer" is a natural gas producer "who is engaged in the production or gathering of natural gas in interstate commerce for resale, but who is not engaged in the transportation of natural gas (other than gathering) by pipeline in interstate commerce." 18 C.F.R. § 154.91(a).

[10] 40 F.R. 32140.

[11] Order Instituting Investigation To Update Prior Staff Study, 40 F.R. 25691.

[12] Notice Of Issuance Of Revised Staff Nationwide Cost Study And Staff Study Of American Gas Association Reserve Additions, 39 F.R. 11310, Docket No. R–389–B (March 21, 1974).

[13] Pennzoil Company, Mobil Oil Corporation, Tenneco Oil Company, Marathon Oil Company, The Superior Oil Company, Exxon Corporation, The California Company, Continental Oil Company and Burmah Oil and Gas Company.

[14] *Pennzoil Company, et al.* v. *F.P.C.*, 5th Cir. No. 75–2961.

[15] National Rate Proceedings—Order Inviting Comment Re Intrastate Gas Market, 40 F.R. 26568.

[16] Order Issuing Staff Rate Recommendations And Prescribing Further Procedures, 40 F.R. 33998.

[17] Order Issuing Clarification of Staff Rate Recommendations and Providing For Comment Thereon, 40 F.R. 49139.

[18] 41 F.R. 14138.

[19] IPR Comments, May 30, 1976, Appendix I.

[20] OEC Recommendations, October 3, 1975, p. 2.

The 1974 JAS data and the 1975 AGA data has since been published, and are incorporated herein.

In summary, the natural gas shortage [21] and shortages of other energy supplies require that this Commission take all prudent steps to insure that the rates allowed for natural gas sold in interstate commerce are adequate to bring forth the requisite supplies to meet demand while protecting the "consumers against exploitation at the hands of natural gas companies." [22] Thus, the Commission faces a formidable task: establishing rates high enough to stimulate additional new gas supplies, but not so high as to burden consumers with prices in excess of those needed to elicit such supplies.

To that end and in accordance with § 2.56a(n) of the Commission's General Policy and Interpretations, we have determined that the uniform national rates for gas qualifying hereunder, as set forth in Section 2.56a(a)(1) (i) and (ii) and Section 2.56a(a)(3) (i) and (ii) of the Regulations, is necessary in order to assure an adequate supply of natural gas for the Nation.

C. POLICY DETERMINATIONS

After careful review and consideration of all the evidence submitted in this proceeding, we conclude that the new base national rate herein established for 1975–1976 biennium gas should be made applicable where:

(i) The sale is made from a well or wells commenced on or after January 1, 1975;

(ii) The sale is made pursuant to a contract for the sale of natural gas in interstate commerce for gas not previously sold in interstate commerce prior to January 1, 1975, except pursuant to the provisions of 18 C.F.R. §§ 2.68, 2.70, 157.22, or 157.29 (including sales made pursuant to those sections as modified by Federal Power Commission Order No. 491, et al.), or 18 C.F.R. § 2.75(n), where such a sale is initiated on or after January 1, 1975, provided that no certificate for the subject sale has been issued under the optional procedure (18 C.F.R. § 2.75).[23]

Rather than increasing the rate for new gas qualifying under Opinion No. 699–H to the rate level for post-January 1, 1975 gas, we believe that a separate rate determination is necessary to reflect the additional cost and productivity data gathered for the period from January 1, 1973 to December 31, 1974, and to reflect increased income taxes resulting from repeal of percentage depletion allowances.

Our decision to modify the policy set forth in Opinion No. 699–H,[24] with respect to the effective date on which gas initially qualifies for a new rate, is based on a determination that the increased costs of exploration and production and the decreased productivity of wells should only be reflected in the rates for the corresponding period, and not for a prior period. Since the attendant cost and productivity data for the 1973–1974 biennium can be considered separately, we have determined that the more recent 1975 data should only be considered prospectively and should not affect a 1973–1974 cost-based national rate. The $1.42 per Mcf rate prescribed herein reflects the current costs of finding and producing new gas and exceeds the rate necessary for the lower costs previously incurred in finding and producing gas qualifying under Opinion No. 699–H.

We are aware of the problems occasioned by the continuance of the vintaging concept. The Commission, however, has a responsibility to minimize severe and harmful economic dislocation due to increased rates.[25] In light of the magnitude of the increase of the rate prescribed herein for post-January 1, 1975 gas over the revised rate for 1973–1974 biennium gas, the Commission must abandon its intended policy to establish a single uniform national rate for gas dedicated or wells drilled after January 1, 1973, and must vintage by a 1973–1974 cost grouping to preclude the exaction of excessive and unjustifiable economic rent from flowing gas.[26]

Although the Commission expressed concern in Opinion No. 669–H that such vintaging could discourage the dedication of new gas supplies to the interstate market,[27] we did not anticipate at that time such a dramatic increase in costs and decrease in productivity, necessitating the rate of $1.42 per Mcf.

The Commission also has considered factors other than the traditional cost-based formulary in establishing this rate. We have elicited comments as to the bearing intrastate prices should have on interstate rates and have considered these prices in establishing the rate. In addition, we have considered the Btu equivalency values of residual oil, distillate oil, crude oil, synthetic natural gas and liquefied natural gas. Accordingly, we believe that the price established herein for post-January 1, 1975 gas is sufficiently high to encourage dedication of additional supplies of natural gas to the interstate market and increased exploratory and production activity.

We are aware that the rate prescribed herein for post-January 1, 1975 results in a 173% increase over the base rate established in Opinion No. 699–H. However, this disparity is substantially lessened when actual costs for the 1973–1974 biennium are considered in lieu of the projected costs utilized in that proceeding.[28] While actual drilling costs for 1973 approximated those projections made in Docket No. R–389–B, the actual dry hole costs and successful well costs for 1974 were, respectively, 57% and 14% greater than those projected. The average 1973–1974 actual dry hole cost was 35% greater and the average actual successful well cost was 3% greater than the trended values used in Opinion No. 699–H. Similarly, exploration and lease acquisition expenditures were substantially greater than those projected while average productivity fell substantially below that used in Opinion No. 699–H. Moreover, it is necessary to make a rate adjustment for future production from the 1973–1974 wells due to the increased income taxes resulting from the repeal of the percentage depletion allowance.[29] When these and other adjustments are made to reflect actual costs and increased tax liability, the rate established in Opinion No. 699–H is increased to $1.01 per Mcf. The disparity between that rate and the rate prescribed for 1975–1976 biennium gas amounts to a 41% increase.

For these reasons, it is necessary to establish a new rate for gas from dedications and wells drilled on or after January 1, 1973 and prior to January 1, 1975. This rate would be applicable where:

(i) The sale is made from a well or wells commenced on or after January 1, 1973, and prior to January 1, 1975;

(ii) The sale is made pursuant to a contract for the sale of natural gas in interstate commerce for gas not previously sold in interstate commerce prior to January 1, 1973, except pursuant to the provisions of 18 C.F.R. §§ 2.68, 2.70, 157.22, or 157.29 (including sales made pursuant to those sections as modified by Federal Power Commission Order No. 491, et al.), or 18 C.F.R. § 2.75(n), where such a sale is initiated on or after January 1, 1973 and prior to January 1, 1975 provided that no certificate for the subject sale has been issued under the optional procedure (18 C.F.R. § 2.75).[30]

The rates prescribed herein will not apply to sales made pursuant to contracts executed prior to or subsequent to the expiration of the term of the prior contract where the sales were formerly made pursuant to the permanent certificates of unlimited duration under such prior contracts which expired of their own terms on or after January 1, 1973, or pursuant to contracts executed on or after January 1, 1973, where the prior contract expired by its own terms prior to January 1, 1973. Such sales will continue to be governed by the rate level, including appropriate annual escalations, prescribed in Opinion No. 699–H.[31]

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[21] The natural gas shortage has been judicially recognized. E.g., *F.P.C.* v. *Louisiana Power & Light Co.*, 406 U.S. 621 (1972); *Placid Oil Company, et al.* v. *F.P.C.*, 483 F. 2d 880 (5th Cir. 1973), affirmed sub nom. *Mobil Oil Corporation, et al.* v. *F.P.C.*, 417 U.S. 283 (1974). *Shell Oil Company, et al.* v. *F.P.C.*, 484 F 2d 469 (5th Cir. 1973), cert. denied sub nom. *Mobil Oil Corp.* v. *F.P.C.*, Nos. 73–438, et al. (June 17, 1974).

[22] *Phillips Petroleum Co.* v. *Wisconsin*, 347 U.S. 672, 685 (1954).

[23] 18 C.F.R. § 2.56(a)(1)(i) and (ii).

[24] See Opinion No. 699–H, ---- F.P.C. ---- slip opinion at 50.

[25] Area Rates For The Appalachian And Illinois Basin Areas, 48 F.P.C. 1299 at 1309–1310 (1972), affirmed sub nom. *Shell Oil Co., et al.* v. *F.P.C.*, 491 F. 2d 82 (5th Cir. 1974).

[26] See Opinion No. 699–H, Concurring Opinion of Commissioner Smith ---- F.P.C. ----, slip opinion at 4.

[27] See Opinion No. 699–H, ---- F.P.C. ----, slip opinion at 50.

[28] See Exhibit 30, infra, for greater detail.

[29] See Int. Rev. Code of 1954, § 613A(b)(2), added by the Tax Reduction Act of 1975, P.L. § 94–12, 501.

[30] 18 C.F.R. § 2.56a(a)(3) (i) and (ii).

[31] 18 C.F.R. § 2.56a(a)(4) and (5).

Opinion No. 749[32] was issued by the Commission on December 31, 1975, establishing "just and reasonable" rates[33] for gas flowing in interstate commerce prior to January 1, 1973. In that proceeding a comprehensive review of rates for such gas was made which resulted in the establishment of national rates. Rather than allowing flowing gas subject to expiring contracts to increase to the rate prescribed herein, we believe that the rate adjustment for such gas under expiring contracts should be limited to the rate level prescribed in Opinion No. 699–H.

Many comments have been received on this issue. Some advocate the continuance of the policy followed in Opinion Nos. 699 and 639 of allowing the renewal contract to receive the new gas rate upon expiration of the term of the prior contract. Other comments argue for the abandonment of this policy.

Our determination of this issue in this proceeding, however, is governed by different circumstances than those which existed when Opinion No. 699 was issued. In that proceeding, the underlying reason for allowing gas subject to expiring contracts the new gas rate was to insure that the additional revenues generated by this class of sales would be available for expanded exploration and development programs. The level of exploratory and developmental dollars generated by this treatment will remain the same as that found necessary in Opinion Nos. 699 and 699–H by permitting an increase to those rates rather than to the rates prescribed herein.

We have carefully scrutinized the disparity between new prices and old prices to avoid an unreasonable increase in rates. By permitting expiring contracts to increase to the rate established in Opinion No. 699–H, a large increase in rates for "flowing gas" is avoided[34] while additional revenues are insured for expanded exploration and development programs which are required to discover and produce new supplies of natural gas.[35]

Accordingly, a new national base rate of $1.42 per Mcf for post-January 1, 1975 gas and a revised rate of $1.01 per Mcf for 1973–1974 biennium gas will apply on or after the date of the issuance of this order. These rates are applicable to all qualifying sales of natural gas in interstate commerce, including oil-well (casinghead) gas, as well as gas-well gas, and shall remain in effect until modified by the Commission.

These rates are applicable only to jurisdictional sales of natural gas within the United States excluding Alaska and Hawaii ("the lower 48"). These national rates are subject to adjustment for Btu content, state and Federal production taxes, applicable gathering allowance, and the annual escalation provided herein.

II. Introduction to Methodology

The basic new gas costing model or methodology that the Commission has employed in the past has its origins in the *Permian I* proceeding.[36] The model was modified with the initiation of the nationwide rate in Opinion No. 699–H by the inclusion of expenditures for unsuccessful ventures[37] in the investment base, and by the adoption of a discounted cash flow analysis to improve the accuracy of the rate of return calculation. Most of the cost studies submitted by the parties in this proceeding are variations upon the *Permian I* model as revised by Opinion 699–H ("699–H model"). However, the Office of Economics has proposed a further substantial revision in the model with the objective of injecting greater realism in the process ("OEC model").

The business of producing natural gas begins with preliminary geological and geophysical activity followed by lease acquisition and then exploratory wildcat activity at one or more sites. If gas in economically recoverable quantities is found, further exploratory (non-wildcat) drilling continues. This may result in new reservoir discoveries and extensions of previous reserve estimates as the field is delineated. Successful exploratory drilling usually is highly productive (as measured by estimated Mcf recoverable per successful foot drilled) but many dry holes also are drilled. Gas production begins when sufficient gas is ready to flow to warrant gathering costs.

Further drilling in the proven field and further delineation usually continues for a number of years. This "developmental" drilling normally results in further extensions of reserve estimates. While the productivity rate is much lower than for exploratory drilling, far fewer dry holes are drilled.

The 699–H model is directed at costing the average successful well that is drilled during the test year. Obviously, the successful wells that are commenced during any period of time are mixed in purpose—some are exploratory wells that discover new fields or reservoirs and others are developmental wells that capitalize upon fruits of earlier exploratory wells and expenditures. Since exploratory activity is the marginal endeavor that is the principal source of enlarged gas supplies for the future, it should be given careful consideration in a prospective rate determination.

The principal differences in cost between exploratory and developmental activity derive from three elements—costs of exploration and lease acquisition, productivity, and the dry-hole expense that is associated with all drilling. The associated overhead and allocated joint costs of developmental wells drilled or being drilled during the 1975–1976 biennium were incurred in earlier years and presumably are lower than the corresponding current costs. However, that fact is offset by the carrying charge that must be added to these costs until production actually commences. The relatively higher productivity of exploratory wells tends to decrease cost, but the relatively higher dry-hole expense tends to increase cost. On the other hand, the relative lower productivity of developmental wells tends to increase cost while the relatively lower dry-hole expense tends to decrease cost. Since these counteracting factors tend to equalize the costs of developmental and exploratory wells, one cannot conclude that the average cost that is derived from the 699–H model is necessarily erroneous.

The burden of future natural gas supply falls predominately upon exploratory activity. The results of the 699–H model should be tested by a methodology that enables the inquiry to be focused upon the exploratory wells that will be drilled in the biennium and the development that follows.

The OEC Comments in this proceeding outline such a methodology which postulates the pattern of development commencing with geological and geophysical expenditures, proceeding through lease acquisition to a successful exploratory well that is drilled in the test year, and ultimately to additional developmental wells. Estimated reserves that are initially discovered through an exploratory well usually will increase over time as the area (field) is further developed and delineated. Witness Marsh in the IPR comments has suggested a statistical method for estimating the amount and rate of the reserve increase.[38] When this data, coupled with reasonable assumptions regarding the timing of developmental expenditures and the depletion rates of the exploratory and developmental wells, is used in the OEC model, the result is a reasonable estimate of the cost of exploratory wells that are drilled in the test year and of the cost of development of the entire project.

Therefore, we will base our rate determination in this proceeding upon consideration of the results of the 699–H and OEC models.

Both of the models employ the same basic cost elements and data. The OEC model relies upon additional data sources for the separation between exploratory and development costs, but these are separate allocations of the same data rather than the use of different data.

The identity of the base data suggests that if reasonable assumptions concerning operating conditions are held constant between the two models, the indicated price will be in the same general range.[39] While the OEC cost studies suggest a lower price than would be pro-

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[32] See Footnote 3, *supra*.

[33] Sections 4(a) and 5(a) of the Natural Gas Act, require that all rates received by a "natural gas company" be "just and reasonable." 52 Stat. 822, 823 (1938); 15 U.S.C. §§ 717c(a), 717d(a), (1970).

[34] Over 500 Bcf of natural gas would fall into this category. This volume would significantly increase in future years.

[35] See Opinion No. 699, ---- F.P.C. ----, slip opinion at 97.

[36] *Area Rate Proceeding* (*Permian Basin Area*), 34 F.P.C. 159 (1965).

[37] *E.g.*, dry hole expense.

[38] IPR Comments, May 30, 1975, Appendix J.

[39] IPR Comments, November 3, 1975, Appendix B, p. 9.

duced by the 699–H model,[40] they contain:

1. An arithmetic error in the initial OEC comments;

2. Unacceptable assumptions regarding operating conditions; and

3. Policy choices that we must reject.

1. The arithmetic error is the omission of the joint costs of Exploratory Overhead, Other Exploration and Lease Acquisition attributable to the 2.36 Mcf of developmental reserves.[41] If all other factors in the initial study were held constant and only the error was corrected, the indicated price would be approximately 90 cents,[42] excluding any allowance for Federal Income Tax. The error was acknowledged in the Revised OEC Cost Studies,[43] but the magnitude of the correction is obscured because the revised study made other changes in the assumptions underlying the model that had the effect of reducing the corrected price, i.e. the level of joint costs and the lag times for preproduction investment were reduced.[44]

2. The OEC study assumes that exploratory wells have depletion lives of 18 years. However, the OEC model terminates both exploratory and developmental production at the end of 18 years with the consequence that the newer developmental wells are assumed to have successively declining productive lives. The final developmental expenditure in the 17th year is thus assumed to lead to a well that depletes in only one year. There is no evidence in the record to support such assumptions, nor could there be. To the contrary, evidence herein and before the Commission in earlier area rate proceedings demonstrates a much longer depletion period for an overall project or field. Experience also suggests that the principal developmental wells in the same field will have a substantially identical number of productive years.

3. OEC recommends that the offshore expenditures be excluded in computing the lease acquisition element of cost.[45] We cannot accept that recommendation for reasons hereinafter discussed. OEC further recommends that the Federal Income Tax considerations be excluded until additional information is available. OEC suggests the value of the accelerated deductions to the industry be ignored and that no income tax allowance be included with respect to the revenue that is derived from the production. The repeal of the percentage depletion allowance by the Tax Reduction Act of 1975 compels us to consider henceforth both the benefits and burdens of existing Federal Income Tax law.

When appropriately corrected and revised, the OEC format provides a broader and more realistic view of the exploration and development process that commences with the exploratory wells which are drilled in the test year. Certainly, the industry does not premise investment decisions in new field development on an assumption that the exploratory wells are the terminal investments and the reserves therefrom are the ultimate recovery potential. Rather, producers undoubtedly consider the complete developmental costs and potential reserves of a field in their exploratory decisions. Initial overhead investment in exploratory activities and lease acquisitions are considered in relation to the ultimate development of the entire field and the decision to proceed is premised on a recovery of these as well as other costs over the productive life of the field. Thus, conceptually, the OEC model when properly applied offer a valid method of establishing rates for the future, both extending and testing the adequacy of the 699–H model.

A. PRODUCTION AND DEVELOPMENT PATTERNS

Both of the models employ a discounted cash flow method of computing the return element; thus, both require assumptions concerning the timing of the incurrence of costs, tax deductions and revenues. In the 699–H model, the principal costs or negative cash flows occur in the preproduction period and the negative cash flows in the production period (operating expenses, etc.) vary proportionally with the timing of the revenue stream or positive cash flows in that period.

The OEC model, however, introduces an additional timing consideration—when do the costs for developmental drilling occur? The OEC studies assume that the developmental well expenditures occur in proportion to, but are lagged one year behind, the annual increment of reserve additions.[46] There is no direct evidence that would support this pattern of development expenditure. In reality, not all changes in reserve estimates are attributable to drilling or to any significant additional expenditure. Production experience is the most significant contributor to reserve estimate revision. The Marsh reserve addition curve begins to flatten out appreciably after 7 to 10 years and reserves added after the 10th year constitute only 11 percent of the 3.36 Mcf total.[47] We find that in the application of the OEC model, it is more reasonable to assume that the developmental expenditures occur on the average over the 10-year period after production initially commences, and that reserve changes thereafter should be attributed to information enhancement rather than to additional outlays. The assumption of earlier development expenditures is to some extent supported by UDC Comments: "developmental drilling in most fields occurs prior to the commencement of production from exploratory wells; and, in many offshore fields, all development drilling occurs prior to that point in time."[48]

We also shall correct the well depletion life error of the OEC study by adjusting developmental expenditures so as to be recovered over the basic fifteen year well-depletion period that we adopt for this opinion. The resultant field production pattern is a somewhat compressed (because of shorter development and depletion periods) version of the pattern suggested by Witness Ogden[49] and should also be compared with the study of offshore fields submitted by Witness Root.[50]

We, of course, recognize that the OEC model could be utilized with other possible and, perhaps, equally reasonable assumptions that would tend to raise or lower indicated prices and that the evidence is sketchy in relation to any assumptions. However, in view of the fact that the OEC model and the integral assumptions do not constitute the sole basis for supporting the rate that is herein established, those evidentiary limitations provide no basis for attacking the ultimate conclusion.

B. OPERATION OF THE OEC MODEL

The OEC model divides the project development into an exploratory phase and a developmental phase. The exploratory phase consists of the expenditures for exploratory overhead, other exploration, lease acquistion, successful exploratory wells and related dry holes and production facilities for those successful wells. The developmental phase contains expenditures for successful developmental wells and related dry holes, production facilities and recompletion. The costs will in turn be recovered from production from both the exploratory and developmental phases.

The exploratory overhead, other exploration, and lease acquisition items apply to both phases, but no division is required since these costs are common to and precede both types of drilling activity.

The drilling costs and production facilities' costs must be allocated between the exploration and development phases, but the significance of the allocation can be overstated. If the basic pattern of development expenditure is established and it is assumed, as we do herein, that equal developmental expenditures produce equal amounts of natural gas and that all development expenditures have the same recovery rates, the price determined by the OEC model is not very sen-

[40] OEC Recommendations, August 4, 1975, p. 2, and October 3, 1975, p. 3.

[41] See pp. 22 and 95, *infra*.

[42] IPR Comments, Sept. 5, 1975, pp. 23–25; Statement of Auten, p. 8; Appendix A, p. 8.

[43] OEC Recommendations, October 3, 1975, pp. 3–4.

[44] IPR Comments, Nov. 3, 1975, pp. 3–5.

[45] IPR Comments, Nov. 3, 1975, Statements of Stark, p. 3 (App. B) and Auten, p. 3 (App. A); UDC Comments, Nov. 4, 1975, Statement of Ogden, pp. 5–6.

[46] OEC Recommendation, October 3, 1975, p. 7.

[47] IPR Comments, May 30, 1975, Appendix J, Figure 5.

[48] UDC Comments, Nov. 5, 1975, pp. 5–6.

[49] UDC Comments, Nov. 3, 1975, Statement of Ogden, Table 2.

[50] UDC Comments, July 24, 1975, Statement 8 of Root, Exhibit A. See also Exhibit 13, infra.

sitive to the allocation of drilling costs and other production facility costs between the exploratory and developmental phase.[51] If, however, either of the assumptions is changed, the price becomes more sensitive to the relative exploratory and developmental unit costs. In any event, it is necessary to describe the method by which drilling costs and production facilities' costs are allocated between the two phases.

Drilling costs consist of successful well expenditures and dry-hole expenditures reduced to a per Mcf basis. Production facilities' cost is directly proportional to unit successful well cost. Unit successful well costs are derived by dividing the cost of successful drilling per foot by the estimated productivity. Dry-hole costs are derived from dry-hole drilling cost per foot divided by productivity multiplied by the ratio of dry-hole footage to successful wells footage. Thus, the process of determining drilling costs for exploration and development requires the division of the two elements. Separate productivities and the relative dry-hole ratios must be established.

Productivity is defined as reserves added divided by drilling footage. Reserves data published by the AGA is divided into four categories: New Field Discovery, New Reservoir Discovery, Extensions and Revisions. The OEC recommendations excluded Revisions because they are not traceable to drilling activity.[52] New Field Discovery and a portion of New Reservoir Discovery[53] are assigned by OEC to the exploratory phase. Successful well drilling footage categories reported by API are New Field Wildcat, Other Exploratory and total. New field wildcat and a portion of Other Exploratory drilling[54] is assigned by OEC to the exploratory phase. The result is:[55]

$$\text{Exploratory productivity} = \frac{\text{Assigned Exploratory Reserves}}{\text{Assigned Successful Exploratory Drilling}}$$

$$\text{Developmental productivity} = \frac{\text{Assigned Developmental Reserves}}{\text{Assigned Successful Developmental Drilling}}$$

UDC objects to the OEC allocation of reserves, asserting that the AGA New Field reserve data includes some reserves that the estimator anticipates will be produced by developmental wells.[56] However, the AGA has consistently urged that its definition of proved reserves includes only reserves that are closely related to actual drilling. In the AGA letter to which UDC alludes, it is stated:

> In * * * (a new exploratory drilling) area, the Committee will estimate *proved* reserves for areas immediately adjacent to wells which have been tested and found productive. Good geophysical data is not considered adequate reason to estimate large undrilled areas of prospective reservoirs at this point in time.[57]

It is, of course, possible that some new Field Discovery reserves should be placed into the developmental phase. But the only impact of such a shift would be that exploratory productivity would be reduced and developmental productivity increased. Exploratory drilling would then have a higher cost and developmental drilling a lesser cost. It was earlier observed that the model that we here employ is not very sensitive to differing unit cost allocations between exploratory and developmental phases.

III. The Rate Determination

A. The timing of expenditures

Both the OEC and 699–H models use discounted cash flow analysis to take account of the timing of the cash outflows and inflows. In DCF analyses, it is convenient to label investments that are made prior to the first revenues with negative numbers, −1, −2, etc. We shall denominate 1976 as Year "0", the year which production is assumed to commence.

The timing of the occurrence of the preproduction expenditure is very much in dispute in the record. The cost elements that must be allocated to appropriate preproduction years are Other Exploration, Exploratory Overhead, Lease Acquisition, Dry Hole (Exploratory only in OEC Model) and Successful Well (Exploratory only in OEC Model). The wide divergence among the comments is displayed in Exhibit 1.

In assessing the conflicting evidence, the overall impact that varying the time periods has upon the DCF models also must be considered. Moving a cash outflow back in time by one year increases its present value at year "0" by the discount rate. However, moving a cash outflow back in time by one year also hypothesizes the expenditure to an earlier year's data. The large increases in expenditure levels of recent years, caused principally by inflation, would be successively removed from the base data by additional lagging of outflows. For example, if dry hole expenditure is placed in year −2 rather than −1, the year for the incurrence of the expenditure would be 1974 rather than 1975. We estimate that the dry hole costs increased by approximately 14.9% between 1974 and 1975, offsetting the additional lag effect.[58] Moving the lease acquisition expenditure date back would lead to a similar counteracting impact. For example, if lease acquisition was moved to year −4, the expenditure year would be 1972. The lease acquisition ratio for the earlier period could be at least 30% less than that which is derived by including the 1973 and 1974 expenditures in the data series. The exploratory overhead and other exploration expenditures are relatively less significant in amount.

Exhibit 1

Comment	Year incurred						
	Opinion 699–H	BNG[1]	BNG[2]	OEC[3]	OEC[4]	IPR[5]	UDC[6]
COST ELEMENT							
1. Other exploratory	−3	----------	−3	−4	−3	−5	−3
2. Exploratory overhead	−3	----------	−3	−4	−3	−5	−3
3. Lease acquisition	−2	(7)	−2	−3	−2	−4	−2
4. Dry hole	−1	----------	−1	−2	−1	−2	−1
5. Successful well	−1	----------	−1	−1	−1	−1	−1
6. Other production facilities	−1	----------	−1	−1	−1	−1	−1

[1] BNG recommendations, Aug. 4, 1975.
[2] BNG recommendations, Mar. 23, 1976.
[3] OEC recommendations, Aug. 4, 1975.
[4] OEC recommendations, Oct. 3, 1975.
[5] IPR comments, May 30, 1975, app. M, statement of Allen, p. 10.
[6] UDC comments, May 14, 1975, statement 7 of Ogden, app. B. Comments exclude Alaska, Appalachia, Gulf of Mexico, and Texas Permian.
[7] The BNG recommendation of Aug. 4, 1975, appears to adopt the Permian I approach to timing, with preproduction outlays occurring 1.5 yr before production commences.

Therefore, the ultimate price in this proceeding is not as sensitive to the varying lag time assumptions as it may first appear. In fact, in the precise circumstance of extraordinary recent cost inflation here presented, the significance is quite minimal.

Witness Allen testified for IPR regarding the experience of Phillips Petroleum Company between 1959 and 1974 on 170 leases in 13 states. He estimates that the average time between initial lease acquisition cost and first revenues was 56 to 63.2 months.[59] While Mr. Allen testified to his opinion that the experience was representative of the industry as a whole, onshore and offshore, we also note the testimony of Assistant Secretary of the Interior Carlson that "[I]f all goes well, the average successful gas discovery will be in production within 3½ to 5 years after the lease sale",[60] and this estimate

[51] The assumption that equal developmental expenditures produce equal amounts of natural gas is simplistic, but the record does not provide sufficient data to permit the finer distinction of progressively declining productivity.
[52] OEC Recommendations, August 4, 1975, p. 6.
[53] OEC Recommendations, August 4, 1975, Table 2, Sheet 1.
[54] *Ibid.*
[55] The OEC method for assigning reserves appears in Tables 2 and 3 of the OEC Recommendations, August 4, 1975.
[56] UDC Comments, Sept. 5, 1975, p. 5.
[57] Letter from Lenard W. Fish, Senior Vice President, AGA, to the Federal Power Commission, Aug. 20, 1974, p. 2, UDC Sept. 5, 1975, App. A.
[58] See Exhibit 7, infra.
[59] IPR Comments, May 30, 1975, Exhibit M, p. 4.
[60] *Id.*, at p. 6.

includes all developmental drilling from the platform. Offshore development involves more elaborate and time consuming preproduction physical activity than onshore development, and we are hesitant to base a nationwide finding upon the experience of a single company when that study suggests an average that exceeds the average offshore period as estimated by the Department of the Interior, and when the report does not reflect the relative mix of onshore and offshore activity. In view of the relatively small impact at this time of a change in the time periods and the lack of definitive evidence of the necessity for change, for this biennial review, we will adhere to the preproduction time lag assumptions that were utilized in Opinion 699–H.

In the DCF analysis we shall continue to reflect the impact of early income tax deductions that are available to producers of natural gas. That approach was adopted in Opinion 699–H. IPR has contended that the 699–H approach was illogical since the Commission there did not include an income tax allowance upon the net revenue.[61] The IPR recently stated that the 699–H "* * * treatment is only appropriate if the Commission is now ready to recognize the existence of a new federal income tax cost applicable to gas."[62]

We herein, consistent with principles established in Opinion 749, include a properly computed income tax payment at the marginal statutory rate of 48% in the cash flow stream of the DCF analysis. It, therefore, is proper to continue to recognize the time value of the accelerated income tax deductions in computing the rate.

The initial BNG Recommendations stated that "the negative tax assumptions utilized in Opinion No. 699–H should be eliminated."[63] Three arguments were offered to support that conclusion but those arguments largely have been overtaken by subsequent events.

First, it was argued that the "negative tax" used in Opinion 699–H would "tend to establish a preference for existing producers and discourage new entrants into that phase of the industry."[64] We note, however, that the "new entrant" by definition has less natural gas production, namely zero, than the amount that is exempted from repeal of the depletion allowance for independent producers.[65] The new entrant will be entitled to take a percentage depletion allowance for several years into the future.[66] The availability of a depletion allowance, for which we have not accounted in this analysis, tends to compensate for any bias embedded in the assumption that intangible drilling costs can be written off immediately against other jurisdictional taxable income. Finally, it is not possible in average rate-making proceedings to account for all possible disadvantages that such a rate might induce.

Second, "no allowance for income taxes has been allowed in existing flowing gas rates, meaning that no taxable income is generated from flowing gas to which this negative income tax can be applied."[67] We have since incorporated into flowing gas rates a six-cents per Mcf allowance for income tax liability.[68] As of July 1, 1976, flowing gas will commence generating a significant income tax component for the industry, which tax can be deferred by reinvestment in new gas exploration and development.

Third, the "time value of money attached to this negative tax is illusory for it does not generate any cash flow—its only effect * * * is to reduce return * * * (or) result in an indirect regulatory intrusion into other non-natural gas activities of the enterprise."[69] Today, the time value is no longer illusory. The industry is realizing or will realize in the near future from its jurisdictional natural gas operations a large amount of taxable income that will be subject to the marginal statutory rate. That income will be derived from rate increases for expiring contracts to the new gas rate established in Opinion 699–H, the increase in rate for gas from wells drilled between January 1, 1973, and January 1, 1975, and flowing gas under Opinion 749. Also, it would be improper to ignore for the long term the impact of the income tax component that we here implement. We do not intrude upon the non-jurisdictional activity of the natural gas producers by recognizing in our rate the immediate cash flow consequences in terms of time value of the income tax deferral (the model does *not* assume a permanent tax saving) that results from continued investment in natural gas exploration and development.

BNG also alludes to but does not implement or advocate,[70] the use of the carry-forward provisions of the Internal Revenue Code[71] to delay the deductions until income is generated by the project. That method was also used without extended comment in a cost study relating to the 699–H price that accompanied several comments.[72] The method would place the focus of the inquiry on revenue and income tax consequences of an individual project or well. However, we do not in this proceeding cost an individual well or a project in isolation. The well or project is the surrogate for the average conduct of the industry in an ongoing enterprise. In fact, the industry does not await production from a new well to deduct the costs of that well—the deduction is taken immediately against taxable income. The value of the tax deduction is realized immediately. It would not be appropriate for us to hypothesize contrary to observed reality.

We also take account of the relatively small investment tax credit that is available for the tangible property investment that is not expensed as intangible drilling costs. We utilize the 30% of successful well cost that is not expensed plus 100% of other production facilities,[73] and apply the investment tax credit of 10%.[74]

B. PRODUCTIVITY

Productivity in terms of Mcf per successful foot drilled is the cornerstone of the analysis used to determine the cost for "new" gas. The productivity for any one year is calculated by dividing the annual non-associated gas reserve additions by the total successful gas footage for that year. Multi-year productivity is the average of annual productivities weighted by drilling footage. In making that computation in the past, the Commission has relied upon the reserve additions published by the American Gas Association and the successful gas well footage published by several sources.[75]

The practice adopted in earlier area rate opinions[76] and in Opinion Nos. 699 and 699–H, and which will be adopted herein, was to average the reserve additions and the successful gas well footage figures over a number of years to determine an average productivity figure that would be used in the calculation of a new gas cost. The magnitude of the productivity calculated by this method is influenced by the number of years that are averaged into the calculation.

The practice of averaging reserve additions and successful gas well footage over a number of years stems from the need to smooth out the year-to-year variation experienced in productivity. Also, the use of multi-year averages helps to correct the known time lag between drilling and discovery and reporting of reserves and to rectify any over or understatement of reserve additions or well footage for a given year or number of years.

Because of the observed instability in year-to-year productivity,[77] the use of

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[61] *Eg.*, Comments, May 30, 1975, Appendix L, p. 22.

[62] IPR Comments, April 23, 1976, p. 8. *See Also*, IPR Comments, May 30, 1975, Appendix H, p. 16, Appendix I, p. 6, Appendix L, p. 21.

[63] BNG Recommendations, Aug. 4, 1975, p. 13.

[64] *Id.* at 12.

[65] I.R.C. § 613 (a), (c), and (d).

[66] *Ibid.*

[67] BNG Recommendations, August 4, 1975, p. 12.

[68] Opinion No. 749, ---- F.P.C. ----, Issued December 31, 1975.

[69] BNG Recommendations, August 4, 1975, p. 12.

[70] Ibid.

[71] I.R.C. § 172.

[72] *See* Initial Comments of Pennzoil Co., *et al.*, Rodman Corporation, Tenneco Oil Co. and Texas Gulf, Inc., all submitted May 30, 1975.

[73] This method was applied in IPR Comments, May 30, 1975, Appendix L, Exhibit DWA–1, Schedule 14, Sheet 3; UDC Comments, May 14, 1975, Statement 7, Exhibit A, Schedule 2, pp. 1– ; and the Comments of Pennzoil Co., Rodman Corp., Tenneco Oil Co. and Texas Gulf, Inc., all filed on May 30, 1975.

[74] I.R.C. § 46. The 10% rate has been in effect since Jan. 22, 1975 and is scheduled to be reduced to 7% after Dec. 31, 1976.

[75] There are several sources for the annual successful gas well footage: World Oil since 1947, Oil and Gas Journal for 1947 to 1965, Joint Association Survey (JAS) beginning in 1959, and the American Association of Petroleum Geologists (AAPG) and the American Petroleum Institute (API) reports, both starting with 1966. Over the years, there has been substantial agreement between JAS, AAPG and API figures while World Oil figures were either greater or less than the other reported footage figures by approximately four to five percent.

[76] E.g., Permian Basin Area Rate Proceeding, 34 F.P.C. 159, 189–192, 377–379 (1965).

[77] BNG Recommendations, March 23, 1976, Schedule 2, Sheet 2.

short-run productivity data would incur the risk of injecting comparable instability into our rate determinations. For example, if in an earlier period we had used the years 1959–1963, our rate determination would have been based upon an average productivity of 509 Mcf per foot drilled. If we had then reviewed the rate four years later, using the 1964–1967 period, the rate would have been based on 712 Mcf per foot drilled. The increase between the two four-year periods would have required a substantial downward revision in the rate. Updating to the next four years, 1968–1971, would have resulted in a large upward revision in the prescribed rate, since the 1968–1971 productivity was 412 Mcf per foot drilled. For the most recent four-year period, 1972–1975, the productivity was approximately 195 Mcf per foot drilled.[79] We, thus, believe that the rate instability that would follow from rates based on short-run productivity would have an adverse effect on future gas supply.

In Opinion No. 699, the Commisison relied upon reserve additions for a ten-year period (1963–1972) to compute the low end of the reasonable cost range and a seven-year period (1966–1972) to compute the high end of this range. The ten-year average resulted in a productivity factor of 552 Mcf per foot drilled while the seven-year period resulted in a productivity factor of 485 Mcf per foot drilled. The Commission ultimately employed the productivity factor of 485 Mcf per foot of successful well drilled in order to reflect the downward trend in productivity and to insure that the rate derived from the cost was sufficient to encourage the exploration and development of more marginal wells.[79]

EXHIBIT 2.—*Productivities (excluding Alaska)*

	AGA non-associated reserves (Bcf)	Drilling footage (thousands)	Productivity (1,000 ft[3])
	(1)	(2)	(3)
1966	16,136	24,391	662
1967	17,284	21,533	803
1968	12,335	20,665	597
1969	6,875	24,064	286
1970	9,351	22,852	409
1971	8,565	22,609	379
1972	7,597	26,743	284
1973	3,717	35,587	104
1974	6,686	38,975	172
1975	9,946	41,898	237
Total 1966 to 1974	88,546	237,419	373
Total 1966 to 1975	98,492	279,317	353
Total 1967 to 1975	82,356	254,926	323
Total 1968 to 1975	65,072	233,393	279
Total 1969 to 1975	52,737	212,728	248

Sources: "(1) Reserves of Crude Oil, Natural Gas Liquids, and Natural Gas in the United States and Canada and United States Productive Capacity," AGA-API-CPA, 1967 through 1975. (2) "Quarterly Review of Drilling Statistics for the United States," (API) and "The American Association of Petroleum Geologists Bulletin" (June 1967).

[79] See Exhibit 2, infra.

[79] See Opinion No. 699, ---- F.P.C. ----, slip opinion at 53.

Among the initial comments filed in this proceeding were those of IPR, in which Mr. Marsh argued that 250 Mcf per foot was an optimistic productivity estimate for 1975–1976,[80] while Mr. Roe recommended a productivity factor of 300 Mcf per foot drilled.[81] Mr. Marsh based his recommendations on the application of the linear least squares method to data for the period 1970 to 1974. Mr. Roe based his recommendations on the most recent four-year average (1971–1974). Mr. Roe added that, at the outside, a productivity factor of 320 Mcf per foot could be used if a five-year average were used (1970–1974).

BNG in its recommendations used productivity factors of 454 Mcf per foot drilled based on a 12-year average (1963–1974) and 375 Mcf per foot drilled based on a nine-year average (1966–1974).[82] OEC, using its new costing approach which differentiated between exploratory and developmental productivity, based its productivity recommendations on data for the 1970–1974 period. OEC's recommendations, as clarified in the October 3, 1975 order of the Commission, utilized an exploratory productivity factor of 801.7 Mcf per foot and a developmental productivity factor of 295.5 Mcf per foot. These correspond to a productivity of 333 Mcf per foot calculated in the traditional fashion that ignores the distinction between the two types of activity.[83]

In response to the Staff recommendations, IPR objected to BNG's use of nine-year and twelve-year periods for averaging data to estimate productivity. In light of BNG's recognition of the downward trend in productivity,[84] IPR argues that these longer historical averages are not representative of future projections. IPR also indicated that the Commission should have no uncertainty as to the reliability of AGA reserve data.[85]

The American Public Gas Association (APGA), on the other hand, attacked BNG's cost estimates for reliance on unverified and untested industry reserve and cost data, and argued that the BNG analysis is a gross understatement of the productivity figure. Moreover, APGA stated that only eight months after the issuance of Opinion No. 699–H, BNG's productivity factor had dropped from 485 Mcf per foot to 375 Mcf per foot, a 22% decline, which would indicate that the underlying industry data is "extremely suspect."[86]

On June 21, 1976, we issued a final Staff report[87] on the investigation of AGA reserve data instituted on June 13, 1975, in this proceeding. In this report BNG concluded that although the AGA reserve additions were not accurately reflected for either the Gulf of Mexico 1971–1972 discoveries or the ultimate reserves at year end 1974, the reserve estimates were reasonable in the aggregate.

The primary reason for the uncertainty of the AGA reserve data is the inaccuracy of discovery dates. Of the 29 fields that the Staff determined from producer data to be 1971–1972 discoveries, five were reported by the AGA to have been discovered in other years, one as far back as 1967; five of the fields had not been reported as being discovered at the end of 1974; and Staff could determine that four of the fields reported by AGA as 1971–1972 discoveries were actually discovered in previous years, one as far back as 1965. On the other hand, in 19 fields where Staff, the producer and the AGA all had reserve estimates for 1971–1972 discoveries, there is only a minor difference in the totals of the producer reserves and the AGA reserves. Staff reserves estimates are approximately 25 percent lower in total, but only because Staff adhered strictly to the AGA definition of proved reserves.

With respect to the reasonableness of the reserve estimates in the aggregate made by or reported to the AGA, we conclude that the estimates averaged over an adequate period of time provide a reasonable basis for estimating productivity. The Staff's report of inaccurate reporting of discoveries, the reporting variance between actual field discoveries and the inclusion of the field reserves in the AGA annual report, and the disparity in reserve additions reported by the AGA reinforce our conclusions that using only the most recent data on reserve additions in the suggested four or five-year period is unreliable, and should not be the primary basis for our decision in this proceeding.

As Exhibit 2 indicates, the recent level of productivity reflects a pronounced decline from earlier years. However, we believe a substantial part of this decline can be explained by the change in the composition of drilling activities over the past four years. As Exhibits 3 and 4 indicate, there has been a significant reduction in the fraction of and change in the composition of drilling footage in the higher productivity offshore drilling. We anticipate that a renewal of offshore drilling activity would increase overall gross productivity.

[80] IPR Comments, May 30, 1975, Appendix J.

[81] Id., Appendix K.

[82] BNG Recommendations, August 4, 1974, pp. 2–8, 14.

[83] OEC Recommendations, October 3, 1975, p. 8.

[84] BNG Recommendations, August 4, 1975, p. 3.

[85] IPR Comments, September 5, 1975, p. 12.

[86] APGA Comments, September 5, 1975, p. 3.

[87] Staff Report On The Updated 31-Lease Investigation, 41 F.R. 26583, June 21, 1976.

EXHIBIT 3.—*API successful well footages, excluding Alaska*

[Thousands of feet]

Year	Offshore			Onshore			Lower 48		
	Exploration	Developed	Total	Exploration	Developed	Total	Exploration	Developed	Total
1967	510	1,333	1,842	3,432	16,258	19,691	3,942	17,591	21,533
1968	648	1,678	2,326	3,078	15,261	18,339	3,726	16,939	20,665
1969	277	1,995	2,272	4,708	17,085	21,792	4,985	19,080	24,064
1970	261	1,615	1,876	3,404	17,572	20,976	3,665	19,187	22,852
1971	411	1,750	2,161	2,917	17,530	20,448	3,328	19,280	22,609
1972	138	1,518	1,656	4,438	20,648	25,087	4,576	22,166	26,743
1973	169	2,348	2,517	5,997	27,073	33,070	6,166	29,421	35,587
1974	106	1,632	1,738	7,559	29,678	37,237	7,665	31,310	38,975
1975	115	1,813	1,929	7,865	32,105	39,969	7,980	33,918	41,898

Year	Offshore total as percent of lower 48 total	Offshore exploratory as percent of total offshore
1967	8.6	27.7
1968	11.3	27.9
1969	9.4	12.2
1970	8.2	13.9
1971	9.6	19.0
1972	6.2	8.3
1973	7.1	6.7
1974	4.5	6.1
1975	4.6	6.0

EXHIBIT 4.—*U.S. gross onshore and offshore productivities (excluding Alaska)*

	AGA nonassociated gas reserve additions (billion cubic feet)[1]			API footage drilled (thousands)[2]			Productivity (1,000 ft³/ft drilled)		
	Off	On	Total	Off	On	Total	Off	On	Total
1966	NA	NA	16,136	NA	NA	24,391	NA	NA	662
1967	4,814	12,470	17,284	1,842	19,691	21,533	2,613	633	803
1968	2,903	9,432	12,335	2,326	18,339	20,665	1,248	514	597
1969	1,399	5,476	6,875	2,272	21,792	24,064	616	251	286
1970	4,490	4,861	9,351	1,876	20,976	22,852	2,393	232	409
1971	3,957	4,608	8,565	2,161	20,448	22,609	1,831	225	379
1972	3,565	4,032	7,597	1,656	25,087	26,743	2,153	161	284
1973	2,094	1,623	3,717	2,517	33,070	35,587	832	49	104
1974	2,393	4,293	6,686	1,738	37,237	38,975	1,377	115	172
1975	5,501	4,355	9,946	1,929	39,969	41,898	2,898	109	237

[1] Source: American Gas Association (AGA), "Reserves of Crude Oil, Natural Gas Liquids, and Natural Gas in the United States and Canada as of Dec. 31, 1975."

[2] Source: American Petroleum Institute (API), "Quarterly Review of Drilling Statistics for the United States.",

Accordingly, we have examined the reserve additions for the most recent ten-year period (1966–1975), nine-year period (1967–1975), eight-year period (1968–1975), and seven-year period (1969–1975). By taking the weighted average gross reserve additions per successful foot drilled for these time periods, we derive average projected productivities of 353 Mcf, 323 Mcf, 279 Mcf, and 248 Mcf per successful foot drilled, respectively. This seven to ten year range of average productivities is the same as that used in Opinion No. 699–H, and is reflected in Exhibit 2, herein.

We have determined that the productivity factors of 279 Mcf and 323 Mcf, per foot drilled, which are derived from eight and nine-year averages, should be used to calculate the "zone of reasonableness" for the estimated cost of new natural gas supplies in this proceeding. Eight and nine-year time spans are of sufficient lengths to insure that reporting lags, lack of information required to make a reserve estimate in any given year, and inaccuracies found in the AGA reports will not unduly influence the end result. At the same time, eight and nine-year averages permit the requisite consideration to be given to the more recent industry experience in finding new supplies of nonassociated and associated natural gas.

We further find that the productivity range of 279–323 per Mcf per foot drilled is appropriate in establishing a just and reasonable rate. These factors fall within the range of the 375 Mcf productivity used by BNG,[29] the 333 Mcf productivity used by OEC,[30] the 250-to-320 Mcf productivity suggested in the IPR comments filed in this proceeding,[31] and the productivity of 291 Mcf estimated by UDC.[32]

We have utilized this productivity range in determining a reasonable cost for producing new gas supplies in order to reflect the downward trend in productivity and to insure that the rate derived from the cost of new gas supplies will be sufficient to encourage the exploration for and development of more marginal gas reserves. These productivity levels also account for the fact that the data for the past four years indicate that there has been a definite decline in the industry's ability to find sufficient supplies of natural gas for the Nation. The Commission has previously recognized that productivity trends would depend upon "whether the dwindling resource effect, or the improved technology will dominate in the future. If the former, productivity over time will decline; if the latter, it may increase."[33] While one or two years of low productivity would not be indicative of the "dwindling resource effect," the data for the past few years show a definite decline in productivity.

The rate prescribed herein based upon a productivity range of 279–323 Mcf per foot drilled should provide an incentive to producers to develop more marginal prospects that were formerly considered uneconomical. The lowering of productivity from that used in Opinion No. 699–H increases the rate allowed for new gas supplies which, in turn, makes more attractive the production of gas from higher cost developments and helps offset higher unit costs associated with gas supplies produced from reservoirs evidencing a low productivity. If we are to reduce the existing gap between supply of natural gas and the reasonable demand therefor, all reservoirs practicably capable of producing significant quantities of natural gas must be found and developed.

The final determination with respect to the appropriate estimate of productivity rests largely upon judgment that reflects consideration of a productivity that realistically may be achieved in this biennium and a productivity that yields a price adequate to induce the necessary drilling activity. We, accordingly, find that the middle of this productivity range provides us with an appropriate basis for determining a just and reasonable rate. The rate of $1.42 per Mcf prescribed herein reflects the use of a productivity factor of approximately 300 Mcf per foot drilled.

We further find that exploratory and developmental productivity estimates reflected in Exhibit 5, are reasonable estimates to use in the application of the OEC model. These estimates fall within the range of the exploratory and developmental productivity estimates determined by OEC.[34] These are also consistent with the overall productivity estimates and Witness Marsh's ratio of ultimate recovery to initial discovery of 3.36:[35]

EXHIBIT 5.—*Productivity reconciliation*

Overall Productivity: 279 Mcf

Activity	Productivity	Relative drilling	Weighted productivity
Exploratory	874	0.095	83
Developmental	217	.905	196
Overall		1.000	279

$$\frac{\text{Overall}}{\text{Exploratory}} = \frac{279}{83} = 3.36$$

[29] BNG Recommendations, August 4, 1975, p. 14.

[30] OEC Recommendations, October 3, 1975, p. 8.

[31] IPR Comments, May 30, 1975. Appendix K, for a five-year period, 1970–1974, a productivity factor of 320 Mcf per foot was estimated. Appendix J: 250 Mcf is deemed an optimistic estimate.

[32] UDC Comments, May 14, 1975, Statement 4, p. 13. Excludes Alaska, Appalachia, Gulf of Mexico and Texas Permian (District 8).

[33] Area Rate Proceeding, et al. (Southern Louisiana), 46 F.P.C. 86, 130 (1971).

[34] OEC Recommendations, August 4, 1975, Table 2, Sheet 1 and Table 3.

[35] IPR Comments, May 30, 1975, Exhibit J.

Overall Productivity: 323 Mcf

Activity	Productivity	Relative drilling	Weighted productivity
Exploratory	960	0.10	96
Developmental	252	.90	227
Overall		1.00	[illegible]

$$\frac{\text{Overall}}{\text{Exploratory}} = \frac{323}{96} = 3.36$$

C. DRILLING COST

The second major factor in the cost of gas production is drilling costs. The basic data from the Joint Association Survey is presented below as Exhibit 6.

EXHIBIT 6.—*Drilling costs per foot (excluding Alaska)*

Year	Successful well cost	Dry-hole cost
1967	22.90	12.14
1968	23.60	12.60
1969	24.35	12.78
1970	26.62	14.33
1971	27.63	15.83
1972	27.58	16.94
1973	27.43	18.93
1974	34.00	26.27

Source: Joint Association Surveys.

In Opinion No. 699–H, the Commission adopted a least squares method for trending actual drilling cost to the 1973 test year. Subsequently, actual data for 1973 revealed that the linear regression line predicted dry hole costs too low and successful well costs too high by equally significant amounts.

Of the three staff studies in this proceeding, all based on data through 1973, two used least squares trending to arrive at a 1976 cost figure for successful and dry hole drilling while the third chose the most recent (1973) figures at the time of the submission. Their estimated drilling costs were:

	Successful	Dry hole
BNG I [1]	$32.61	$18.78
BNG II [2]	27.43	18.93
OEC [3]	32.61	19.78

[1] BNG recommendations, Aug. 4, 1975.
[2] BNG recommendations, Mar. 23, 1976.
[3] OEC recommendations, Aug. 4, 1975.

IPR approved of updating available data, but chided the Commission for being deficient in prescience and advocated the use of more judgment and a curvilinear regression line to provide a more reliable estimate.[95] Utilizing such method, Witness Auten for IPR estimated successful well cost for 1974 of $28.07 per foot and for 1975 of $28.08 per foot.[96]

Witness Ogden for UDC estimated that 1974 drilling costs would be 40% greater than 1973.[97]

The actual 1974 successful well cost reported by JAS was $34.00 per foot, an increase of approximately 24% over 1973, $5.93 greater than Witness Auten's estimate and $3.75 greater than would be indicated by a 1973–1974 linear regression line. Dry hole cost has increased similarly. A linear regression line would predict 1974 costs between approximately $18.00 and $22.00, varying with the length of the series used to fit the line. Witness Auten, relying upon curvilinear regression analysis, estimated the 1974 dry hole cost at $20.49. Witness Ogden applied his estimated 40% increase in drilling to dry holes. The actual 1974 dry hole cost reported by JAS was $26.27, an increase over the 1973 level of approximately 39%.

The extraordinary inflation of recent years suddenly has affected drilling costs to a degree that no submitted statistical trending method would yield an accurate prediction. We are, however, again confronted with a "test" year for drilling, 1975, that is one year ahead of the available JAS cost data. The continuing general inflation requires that the task of updating actual data be once again undertaken. There is no comprehensive, long-term price index for petroleum industry drilling. The IPAA for several years published only quintennially a comprehensive oil and gas drilling cost survey and index, but in 1973, the IPAA commenced issuing the reports annually.[98] Between 1969 and 1973, the IPAA index tracked actual experience as reported by JAS reasonably closely. While the 1969 index was 100 and the 1973 index was 131.5,[99] the average increase in successful well and dry hole costs as reported by JAS between 1969 and 1973 was approximately 24%. Furthermore, the extraordinary increases from 1973 to 1974 provide a rigorous test of accuracy. The 1973 IPAA cost per foot index is 83.0, 1974 is 100.0, and 1975 is 114.9. If the 1973 and 1974 IPAA indices had been used to estimate 1974 JAS costs, the indicated costs per foot would have been $33.05 (compared to $34.00 actual) for successful gas wells, and $22.81 (compared to $26.27 actual) for dry holes.[100] For that period, the accuracy of the IPAA index substantially exceeds the accuracy of any submitted form of regression analysis.

The IPAA index shows a further 14.9% increase from 1974 to 1975.[101] The continued upward pressure upon oil and gas-well drilling costs is borne out by the Bureau of Labor Statistics (BLS) index for drilling machinery which increased 24% between 1974 and 1975, and 14% from February 1975, to February 1976.[102] Also the BLS shows similarly escalating wage costs; average hourly earnings rose 14.6 and 12. 2 percent between February 1974–75 and 1975–76, respectively.[103] Thus, the IPAA appears to be a reasonably accurate reflection of actual experience, and we here adopt it in preference to regression analysis for the purpose of trending the 1974 JAS data to the 1975 test year.

To obtain the 1975 drilling costs per foot we converted the 1973 and 1974 JAS costs to constant dollars, using the IPAA index for drilling costs per foot. The averages of the 1973 and 1974 constant dollar costs for successful wells and dry holes of $33.53 and $24.56 per foot, respectively, were adjusted to 1975 dollars by applying the 14.9% increase indicated by the IPAA index. The 1975 projected costs are:

EXHIBIT 7.—*Well costs (excluding Alaska)*

[Dollars per foot]

Year	Current dollars		Index [2]	Constant dollars	
	Successful	Dry hole		Successful	Dry hole
	(1)	(2)	(3)	(4)	(5)
1973	27.43	18.99	83.0	33.05	22.81
1974	34.00	26.27	100.0	34.00	26.27
1975	[1] 38.53	[1] 28.20	114.9	[illegible]	[1] 24.54

[1] Projected: 1973–74 average × 114.9.
[2] Average 1973–74.

Sources (1) and (2): Joint Association survey. (3): IPAA report of the cost study committee, "Summary of Committee Activities," May 1976, adjusted index. (4) and (5): (1) and (2) divided by (3) for 1973 and 1974.

1. *Successful well costs*

The estimated successful well costs per Mcf for 1975 are obtained by dividing estimated successful well costs per foot by the estimated productivity of such drilling. In the 699–H model, the cost per foot of drilling of $38.53 divided by the overall productivities of 279 and 323 yields a succesful well cost of 13.81 and 11.93 cents per Mcf, respectively. The various cost studies submitted herein all utilized the same methodology, but, of course, arrive at different unit costs because of differing estimated well cost and productivity.

To convert the overall successful well cost to the separate elements of exploratory cost and developmental cost for the OEC model, the same base drilling cost is used for both, but the differenng produc-

[95] IPR Comments, May 30, 1975, Appendix L, p. 5.
[96] Ibid. Chart 2.
[97] UDC, May 14, 1975, Statement 7, p. 5.
[98] Independent Petroleum Association of America, Report of Cost Study Committee, May 1976.
[99] IPAA, Report of Cost Study Committee, June 1975.
[100] Exhibit 6, supra.
[101] Exhibit 6, infra.
[102] Wholesale Prices and Price Indexes, Bureau of Labor Statistics, selected volumes; Oil Field Machinery and Tools (Code No. 1191).
[103] Employment and Earnings, Bureau of Labor Statistics, selected volumes; Crude Petroleum and Natural Gas Fields (SIC 131–2), average hourly earnings.

tivites of exploratory and developmental drilling yield separate successful well costs as follows:

Productivity=323 Mcf/ft.:
Exploratory successful well cost=
38.53=4.01¢/Mcf
960
Developmental successful well cost=
38.53=15.29¢/Mcf
252
Productivity=279 Mcf/ft.:
Exploratory successful well cost=
38.53=4.41¢/Mcf
874
Developmental successful well cost=
38.53=17.76¢/Mcf
217

2. *Dry hole costs*

Dry hole costs are estimated by multiplying the drilling cost per foot by the fraction of dry hole feet drilled per successful well foot drilled to obtain dry hole cost per successful foot and then dividing by the productivity of successful drilling to obtain dry hole costs.

The dry hole to successful well footage factor is derived by allocating dry hole footage between oil and gas production and relating the allocated gas dry hole footage to successful gas well drilling footage.[104] Both BNG studies use a dry hole to successful well factor of .84 derived from 1974 data. IPR used a factor of 1.0,[105] the same as used in Opinion No. 699–H. This factor has been declining in recent years. The data from 1969 through 1974 shows a more or less steady decline. The factors for more recent years are:

1973	.85
1974	.84
1975	.80

We find that the factor for the most recent year is a reasonable projection for the future and we adopt .80 as the factor for this proceeding.

Historically, the Commission has increased the dry hole factor by 1.08 to reflect an earlier finding that deeper dry hole drilling occurs where the objective is non-associated natural gas. There is no evidence that would modify that earlier finding and we adopt it here.

We, therefore, find the dry hole cost for 1975 to be:

$28.20×.80×1.08÷323=7.54 cents per Mcf.
$28.20×.80×1.08÷279=8.73 cents per Mcf.

In the OEC model dry hole costs for exploratory and developmental drilling activity follow the same logical development, using their respective dry hole factors and productivities:[106]

Productivity=323
Exploratory:
28.20×4.98×1.08÷960=15.80¢/Mcf
Developmental:
28.20×.3717×1.08÷252=4.49¢/Mcf
Productivity=279
Exploratory:
28.20×4.98×1.08÷874=17.35¢/Mcf
Developmental:
28.20×.3717×1.08÷217=5.22¢/Mcf

D. OTHER PRODUCTION FACILITIES

The generally accepted method for estimating other production facilities cost is to use a fraction of successful well costs. This fraction is the ratio of other production facilities costs plus the cost of production overhead investment to successful well costs as reported to the Commission by producers and pipeline affiliates.

All of the cost studies in the record adopt this method, differing only with respect to the fraction employed. UDC used the fraction 0.226 that was adopted in Opinion No. 699–H[107] and was derived from data in Docket No. AR69–1. BNG derived a 0.232 fraction from the more recent data in Docket R–478.[108] OEC adopted the BNG figures.[109] IPR, also relying upon data in Docket No. R–478, computes the fraction at 0.268.[110] The difference between BNG and IPR is attributable principally to the inclusion by IPR of a $152,568 item for "Incomplete Construction Application To Production."[111] We find that it is appropriate to include the cost of incomplete construction applicable to production to make the base data consistent. The Docket No. R–478 well costs data include expenditures for drilling that is not complete at the reporting date, and it therefore is proper in developing the ratio to include the comparable item for incomplete production facilities. We therefore find the ratio to be 0.268.

Productivity=323
Other production facilities=
11.93×0.268=3.20¢/Mcf
Productivity=279
Other production facilities=
13.81×0.268=3.70¢/Mcf

We employ the same cost per Mcf for other Production Facilities in both the 699–H and OEC models.

E. OTHER EXPLORATION

The submitted cost studies offer several methods for computing the Other Exploraton Cost element. BNG followed the traditional method of multiplying the lease acquisition cost by the ratio of national other exploration costs divided by national lease acquisition costs. Initial BNG comments determined the ratio to be 0.3042 on the basis of 1972–73 data[112] while the subsequent BNG comments found the ratio to be 0.5258 based upon the 1967–73 average.[113] IPR used a slightly more elaborate process but maintained the relationship of Other Exploration costs to Lease Acquisition Costs. IPR trended its data to 1975 and found the cost to be 4.18 to 5.20 per Mcf.[114] UDC combined national other exploration costs and national exploration overhead expenditures and related them to national dry-hole expenditures.[115]

Given the erratic nature and the basic determinants of lease acquisition expenditures, a stable relationship between Other Exploration and Lease Acquisition is not to be expected.

OEC related Other Exploration costs to successful well costs (a method used by IPR in Docket No. R–389–B) and found a more stable relationship.[116] Given the basic arbitrary nature of these allocated costs, no better relationship could be expected. We therefore adopt a ratio based upon successful well costs and average data for the five years 1970–1974 as reflected in Exhibit 8.

EXHIBIT 8.—*Exploratory Other Cost*

(Millions of dollars)

Year	Exploratory other	Gas Allocation factor	Gas other exploratory costs	Successful well costs	Fraction
(1)	(2)	(3)	(4)	(5)	(6)
1967	740			502	
1968	770			494	
1969	782			606	
1970	728	0.3764	279	618	0.451
1971	746	[illegible]	293	[illegible]	.478
1972	788	[illegible]	299	802	.373
1973	867	.3704	270	998	.271
1974	1,174	.4538	[illegible]	1,267	.267
Average 1970 to 1974					.368

Sources: (2): JAS. (3): OEC, table 7, column (4). (4): (2, lagged 3 years) times (3). (5): JAS. (6): (4)/(5).

Other Exploration costs occur in year −3 in our models; therefore, the Other Exploration expenditures attributed to gas are lagged three years behind successful well costs in developing the fraction. A two-year lag would be more precise for the 699–H model since it assumes that all drilling occurs in year −1. The OEC model spaces drilling over several years and year 0 is assumed to be the 50th percentile year. There would be no significant difference in the ratio between two and three-year lags and we therefore use the same ratio in both models. We find Other Exploration to be 0.368 of successful well costs.

Productivity=323
Successful well=11.93×0.368=4.39¢/Mcf
Productivity=279
Successful well=13.81×0.368=5.08¢/Mcf

[104] The allocation data is contained in Appendix A for 1974 and 1975.
[105] IPR Comments, May 30, 1975, Appendix L, Exhibit DWA–1, Sheet 2.
[106] See Appendix B, attached hereto, for the dry hole factor determination.
[107] UDC Comments, May 14, 1975, Statement 7, Exhibit A, Schedule 2, Page 2.
[108] BNG Recommendations, August 4, 1975, Schedule A–4, and March 23, 1976, Schedule 4.
[109] OEC Recommendations, August 4, 1975, Table II, and October 3, 1975.
[110] IPR Comments, May 30, 1975, Exhibit DWA–1, Schedule 6.
[111] Ibid.
[112] BNG Recommendation, August 4, 1975.
[113] BNG Recommendation, March 23, 1976.
[114] IPR Comments, May 30, 1975, Appendix, p. 12.
[115] UDC, May 14, 1976, Statement 7, Exhibit A, Schedule 2.
[116] OEC Recommendation, October 3, 1975, Table 14.

F. EXPLORATORY OVERHEAD

BNG, OEC and IPR follow Opinion No. 699–H and relate Exploratory Overhead to Exploratory Other costs plus dry-hole costs. UDC combined Exploratory Overhead with Other Exploration and related both directly to dry-hole costs. BNG and OEC used a fraction of .1319. IPR trended data to 1975 and arrived at a fraction of 0.1509. In the model used herein, the expenditure occurs in year –3 or 1972, and thus there is no necessity to trend data. Given the time sequence of cash flows we are observing, technically the Exploratory Overhead should be related to Other Exploration in year –3 and to dry-hole costs in year 0. But given the small difference that such an elaborate procedure would make, we use a concurrent relationship and derive an average fraction for 1967–74 data of 0.133 as developed in Exhibit 9.

EXHIBIT 9.—*Exploratory overhead costs*

[Millions of dollars]

Year	Exploratory other	Exploratory overhead	Dry hole costs	Coincident fraction
(1)	(2)	(3)	(4)	(5)
1967	746	206	802	0.133
1968	770	204	826	.128
1969	782	210	868	.126
1970	728	189	873	.118
1971	746	206	864	.128
1972	766	239	1,006	.135
1973	807	293	1,070	.151
1974	1,174	387	1,660	.137
Total 1967 to 1974	6,573	1,934	7,989	.133

(2) through (4), Source: JAS
(5) = (3)/[(2)+(4)]

We find exploratory overhead costs to be:
Productivity = 323
Exploratory overhead = 0.133 × [4.39 (OE) + 7.54 (dry hole)] = 1.59 cents per Mcf.
Productivity = 279
Exploratory overhead = 0.133 × [5.08 (OE) + 8.73 (dry hole)] = 7.84 cents per Mcf.

G. LEASE ACQUISITION

All of cost studies submitted in this proceeding relate lease acquisition costs to successful well data. BNG and UDC used the ratio of total lease acquisition costs to total successful well costs.[117] IPR converted lease acquisition expenditures to dollars per foot of successful wells drilled.[118] OEC allocated lease acquisition costs to gas on a relative value basis and then related gas lease acquisition costs in period –2 to successful gas well costs in period zero, following the timing scheme we adopt here.[119]

All these procedures reveal that there is no systematic relationship between the two components, nor should there necessarily be one. Lease acquisition costs will fluctuate with both the offshore lease activity by the Federal government and the prospective price/cost relationship assumed by producers, while successful well costs or footage drilled should exhibit greater stability. As shown in Exhibit 10, lease acquisition costs increased greatly in 1973 and 1974, so that, depending upon the time period over which we choose to average for our projection purpose, the ratio of lease acquisition to successful well costs or footage drilled could vary greatly. At the one extreme, using 1973–74 data, we find the ratio of the lease acquisition cost to producing well cost to be 1.97, while for the 1967–72 period the ratio is 0.67.

EXHIBIT 10.—*Lease Acquisition Cost*

[Millions of dollars]

Year	Lease acquisition cost	Cost of producing wells	Fraction
(1)	(2)	(3)	(4)
1967	829	1,497	0.55
1968	1,578	1,583	1.00
1969	1,137	1,723	0.66
1970	714	1,706	0.42
1971	643	1,507	0.43
1972	1,722	1,808	0.95
1973	3,646	2,005	1.82
1974	5,659	2,707	2.09
Total 1973 to 1974	9,305	4,712	1.97
Total 1967 to 1972	6,622	9,824	0.67
Total 1967 to 1974	15,927	14,536	1.10

Sources (2) and (3): JAS, joint oil and gas costs. (4) = (2)/(3).

Given this variability and the underlying process, we find it reasonable to assume the 1967–74 average lease acquisition costs are 1.10 times the cost of successful wells. This should be compared with the ratios in the record: 1.408 in the initial BNG cost study;[120] 0.868 in the subsequent BNG cost study;[121] the effective ratio of 1.42 submitted by IPR;[122] and ratio of .507 implicit in the OEC cost study.[123]

OEC contends that offshore lease acquisition costs should be excluded from the cost computation because they have been determined by the profit prospects while onshore lease acquisition costs are a reasonably accurate measure of the value of the land in alternative uses and the damage associated with drilling and production operations.[124]

It can equally well be argued that since the offshore productivity is much higher than the onshore productivity the high offshore lease costs are simply reflective of the true resource value of the natural gas. That value belongs to all citizens of the United States, not merely to the bare majority who consume the bulk of interstate natural gas. It is quite appropriate for the government to demand a price for offshore leases that returns the true value to the rightful owners through the U.S. Treasury.

In any event, the argument is somewhat academic in the context of our decision. In fact, the Department of the Interior follows a policy of rejecting bids that do not adequately reflect the value of the reserves underlying the leases. In addition, the natural gas producing industry has committed large sums of money for existing leases. We must therefore include an increment for lease acquisition cost in our rate determination that reflects costs already incurred by the industry, and that recognizes the realities of reasonable offshore costs to support a high level of future leasing.

We thus apply the ratio of 1.10 to successful well costs to obtain the estimated lease cost component:

Productivity = 323
Lease acquisition cost = 11.93 × 1.10 = 13.12¢/Mcf
Productivity = 279
Lease acquisition cost = 13.81 × 1.10 = 15.19¢/Mcf

H. RECOMPLETION AND DEEPER DRILLING

The allowance for recompletion and deeper drilling originated in the *Permian II* proceeding[125] where we found that such expenditures were approximately three to five percent of successful well costs.[126] Based upon successful well costs at the time, the amount was .21 cents per Mcf. In Opinion 699, the Commission on the basis of the cost studies submitted by the parties allowed .20 cents per Mcf without relating it to the successful well costs. In this proceeding, IPR trended the percentage and suggested that the allowance should be 5.5 percent of the successful well cost.[127] The other cost studies in this proceeding used the 0.20 cents per Mcf derived from Opinion 699–H. In view of the significant increases in drilling costs in recent years, we find that the recompletion and deeper

[117] BNG Recommendations, August 4, 1975, Schedule A–3, March 23, 1976, Schedule 3. UDC Comments, May 14, 1975, Statement 7, Exhibit A, Schedule 9. The UDC study relates only to onshore areas and excludes also Alaska, Appalachia, and Texas Permian so the derived ratio is quite low.

[118] IPR Comments, May 30, 1975, Appendix L, pp. 8–10.

[119] OEC Recommendations, October 3, 1975.

[120] BNG Recommendations, August 4, 1975, Schedule A–3.

[121] BNG Recommendations, March 23, 1976, Schedule 3.

[122] IPR Comments, May 30, 1975, Appendix L, Exhibit OWA, Schedule 1, Sheet 1.

[123] OEC Recommendations, October 3, 1975, Table 13.

[124] OEC Recommendation, August 4, 1975, pp. 8–9.

[125] Area Rate Proceeding (Permian Basin Area), 50 FPC 390, 453 (1973).

[126] Opinion 699, June 21, 1974, at p. 78 (mimeo).

[127] IPR Comments, May 30, 1975, Appendix L, pp. 7–8.

drilling allowance should be increased to remain in the three to five percent range of successful well costs and should be established at .50 cents per Mcf.

I. OPERATING EXPENSES AND REGULATORY EXPENSES

All cost studies use essentially the same operating expense of 3.10 cents per Mcf.[120] That amount was derived initially from data in *So La II*[121]; was used in Opinion 699 and was reconfirmed by data from Docket R–478.[122] We find that the amount of 3.10 cents per Mcf should be applied in this proceeding.

In Opinion 699–H the Commission adopted .20 cents per Mcf as the allowance for regulatory expense. IPR and UDC continued the use of that amount.[123] However, a subsequent analysis by BNG of data in Docket R–478 suggests that the allowance should be reduced to .10 cents per Mcf and BNG proposed that amount in this proceeding.[124] We accept the latest available data and find that regulatory expense to be .10 cents per Mcf.

J. WORKING CAPITAL

All parties used the methodology employed in Opinion No. 699–H to compute working capital, differing only in the parameters applied.

The basic methodology assumes working capital is needed to support (1) direct exploratory and production expenses, (2) related materials, supplies and prepayments, and (3) "lease play". Items in the first set are assumed to amount to one-eighth of the annual expenditures (corresponding to a 45-day collection period). Items in the second set are related proportionally to the first, and lease play requirements are proportioned annual lease costs.

UDC employed the same proportionality factors that were used in Opinion No. 699 and which were derived from the data in Docket No. AR69–1. BNG, OEC and IPR, on the other hand, derive their proportionality factors from the data in Docket No. R–478 and we believe the more recent data is preferable.

While BNG, OEC and IPR all agree on the proportionality factors of 1.48 for the items related to production expense and 1.5 for lease play, there is slight disagreement between the first two and the latter on the factor for items related to exploratory expenses, 1.21 and 1.2357, respectively. We accept the former. Thus we obtain the working capital needed to produce 1 Mcf per year as:

Productivity = 323

1.5 × 13.12 (lease acquisition) + ⅛ [1.48 × 3.10 (production expenses) + 1.21 × 13.52 (exploration expenses)] = 22.30¢

Productivity = 279

1.5 × 15.19 (lease acquisition) + ⅛ [1.48 × 3.10 (production expenses) + 1.21 × 15.65 (exploration expenses)][125] = 25.73¢

Since we are assuming production of 1 Mcf over 18 years (−3 to +14) one eighteenth of the above figures are appropriate:

$$\text{Working capital} = \text{in} -3 = \frac{1}{16} \times 22.30 = 1.24¢/\text{Mcf}$$

$$\text{Working capital} = \text{in} -3 = \frac{1}{16} \times 25.73 = 1.43¢/\text{Mcf}$$

Recovery is assumed to occur at the end of +14.

323	279

K. ALLOCATION OF COST TO LIQUIDS

Some liquid hydrocarbons are produced jointly with most nonassociated natural gas. The price of the natural gas is subject to the jurisdiction of this Commission, but the price of the liquid hydrocarbons is not. A portion of the total cost of exploration and development for the joint products must be assigned to the liquids to prevent the natural gas consumer from bearing an excessive cost burden, but, since the products are joint, there is no single correct method of allocation. We have recently reviewed various allocation methods in Opinion 749,[126] and concluded that the "modified-btu" method was the most appropriate method for flowing gas.

Historically, the Commission has utilized the "net liquid credit" method for new gas costing. With that method, the estimated net revenues to the producer from the three basic types of liquids—lease condensate, plant condensate, and plant liquids—are related to a single Mcf of natural gas production,[127] and treated as a credit in the process of determining a price that is based upon the total costs of exploration, development and production for natural gas and liquids. Thus, the net liquid credit method inherently regulates, indeed it insures, the rate of return recovery from liquids production at the level determined to be just and reasonable for natural gas. The producer is ensured, but limited to, the just and reasonable rate of return for the liquids, without regard to the return that the marketplace might dictate therefor.

The BNG Comments and OEC Comments herein all utilized the same net liquid credit estimate of 8.45 cents per Mcf that was derived upon a 1974 Staff estimate of prices.[128] IPR submitted a cost study that utilized the 2.89 cents net liquid credit from Opinion No. 699. That was based upon pre-1973 prices,[129] which, of course, were significantly lower than the current liquid price levels. UDC proposed a "vapor volume" method by which costs are allocated upon the basis of the relative volume of the reservoir that is occupied by the respective products.[130] UDC assigned approximately 2.5% of costs to liquids.

In Opinion No. 749 we rejected the allocation methods that are based solely upon physical characteristics, such as volume or relative Btu content. We therein determined that the highest degree of fairness was most likely to result from an allocation method that is founded upon the relative economic values as established in unregulated markets. That proposition is applicable equally to the gas-liquids allocation in the costing of new gas. The net liquid credit method relies upon the economic values of only one of the products (the liquids), ignores relative values and places the benefits, as well as the burdens of regulation upon the unregulated product. On the other hand, the modified-Btu method is based upon the estimated relative unregulated prices of both of the joint products. Thus it allows the markets to regulate the return on the liquids. We reaffirm that the modified-Btu method is the most appropriate allocation method.

Having recently reviewed the data and established a prospective modifying factor in Opinion 749, we reaffirm the factor of 1.5 for the condensate liquids.

The liquids that are extracted in the processing plant consist largely of the heavier liquefied petroleum gases, and some light gases e.g. propanes and butanes. These products have a lesser Btu-content per barrel, a lesser relative value, and are more nearly related to natural gas than the condensate, which is similar to a light crude oil. Therefore, we find that the plant-extracted liquids should be placed upon Btu parity with natural gas and the modifying factor should be 1.0. The most recent available production data for 1975 from the Bureau of Mines and the AGA is used to establish the prospective allocation. The allocation ratios are derived from Exhibit 11. We find that 9% of the costs should be assigned to liquid production, and the remaining 91% assigned to natural gas.

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[120] IPR arrives at 3.03 cents because of an assumed 17% royalty. IPR Comments, May 30, 1975, Appendix L, Exhibit DWA–1, Schedule 9.

[121] Area Rate Proceeding (Southern Louisiana Area), 46 FPC 86, 133 (1971).

[122] Opinion 749, issued Dec. 31, 1975.

[123] IPR Comments, May 30, 1975, Appendix L, Exh. DWA–1, Schedule 1, Sheet 1. UDC, May 14, 1975.

[124] BNG Recommendations, August 4, 1975, March 23, 1976.

[125] Exploration Expenses:

Exploratory O/H	1.59	1.84
Exploratory other	4.39	5.08
Dry Hole	7.54	8.73
Total	13.52	15.65

[126] Opinion 749, ____F.P.C.____, Dec. 31, 1975, slip opinion at pp. ____.

[127] See BNG Recommendation, Aug. 4, 1975, Schedule B–10.

[128] Id. See also, BNG Recommendation, March 17, 1976; OEC Recommendation, Aug. 4, 1975, Table 12.

[129] IPR Comments, May 30, 1975, Appendix L, Exhibit DWA–1, Schedule 1, Sheet 1.

[130] UDC Comments, May 14, 1975, Statement 4, p. 14, tSatement 7, p. 7.

EXHIBIT 11.—*Weighted average British thermal units of plant liquids excluding plant condensate* [1]

1975 production	(1,000 bbl)	Percent volume	MMBtu/bbl	Weighted average British thermal unit content
LPG and ethane	[2] 444,086	76.5	[3] 4.011	3.0[illegible]
Other liquids	[2] 136,246	23.5	[3] 4.620	1.0[illegible]
Total	580,332	100.0	----------	4.154

[1] Weighted average plant liquids=4.154 MMBtu/bbl.
[2] Bureau of Mines (BOM), mineral industry surveys.
[3] BOM publications.

Modified British thermal unit calculation

	1975 production (1,000 bbl)	MMBtu/bbl	Modified	Lease share (percent)	Modified British thermal units
Plant liquids	[1] 278,973	4.154	[2] 1	[3] 34	394,010,306
Plant cond	15,626	[4] 5.4	[4] 1.5	[3] 95	120,242,070
Lease cond	133,124	[4] 5.4	[4] 1.5	100	1,078,304,400
Total					1,592,556,776

[1] Calculated from AGA and BOM data.
[2] Estimated from published price data on plant liquids.
[3] Staff comments in RM75-14.
[4] Opinion No. 749.

	British thermal units
1975 Associated Gas production [1] equals 15,778 billions cubic feet times 1.024 [2]	16,156,672,000
Liquids	1,592,556,776
Total	17,749,228,776
Percent to liquids	8.97
Percent to gas	91.03
Total	100.00

[1] AGA Reserves Report, table VIII.
[2] BOM.

L. DEPLETION PERIODS

The assumed depletion rate and life for the well or project determines the rate of recovery of the investment and thus significantly affects the amount of return on investment that is required and the resultant cost-based price. In *Permian I* [139] the Commission adopted the examiner's finding of a 20-year well life and level annual production. The 20-year period was derived from the typical contract term of that era. The producers argued that the actual well life was at least 22 years, but the Commission rejected the exception on the ground that the bias was more than offset by the level production assumption. The Commission noted that wells commonly do not produce at a level rate, rather "production begins to decline some 7–12 years after the well begins to flow" [140] with the result that cost recovery is more accelerated than cost recovery under level production.

In *SoLa I* [141] the Commission perceived a "downward" trend in the depletion period and relied upon the cost studies that assumed an 18-year depletion period. In *Permian II* [142], the Examiner noted the admission by the Producers that an accelerated draw-down was occurring and stated that a "level closer to 18 years than 20 years is clearly indicated * * * " [143]

The Commission again addressed the issue of declining depletion periods in Opinion No. 699, observing that the "present needs for additional supplies of natural gas have caused reservoirs to be depleted at greater rates than in the past." [144] The Commission specifically rejected the 20-year period and adopted an 18-year period, noting that even it might be "somewhat overstated." [145] The evidence in this proceeding and the evidence in the records of other recent proceedings before the Commission, suggest that the 18-year period indeed is an overstated average for the product of current and future drilling.

First, an analysis of the FPC Form 15 data demonstrates a pronounced trend over the past ten years toward more accelerated production rates from reserves dedicated to interstate pipelines. Exhibit 12 displays the ratio of annual production to the most recent reserve estimates at the end of the year for the fields. The table demonstrates that the more recent fields added to Form 15 display progressively more rapid rates of depletion. For example, using the third year of field life as a baseline, the percentage of production in that year in relation to the gross reserve estimate (cumulative production plus remaining reserves) for the fields at the end of that year has increased steadily from 3.9% for fields added in 1964 to 9.2% for fields added in 1971. We recognize that Form 15 data includes associated, as well as nonassociated reserves and thus may tend to understate actual rates of take in nonassociated gas fields. But that tends only to support the observed trend.

[139] Area Rate Proceeding (Permian Basin Area) 34 F.P.C. 159 (1965).

[140] Id. at 199.

[141] Area Rate Proceeding (Southern Louisiana Area) 46 F.P.C. 86, 131 (1971).

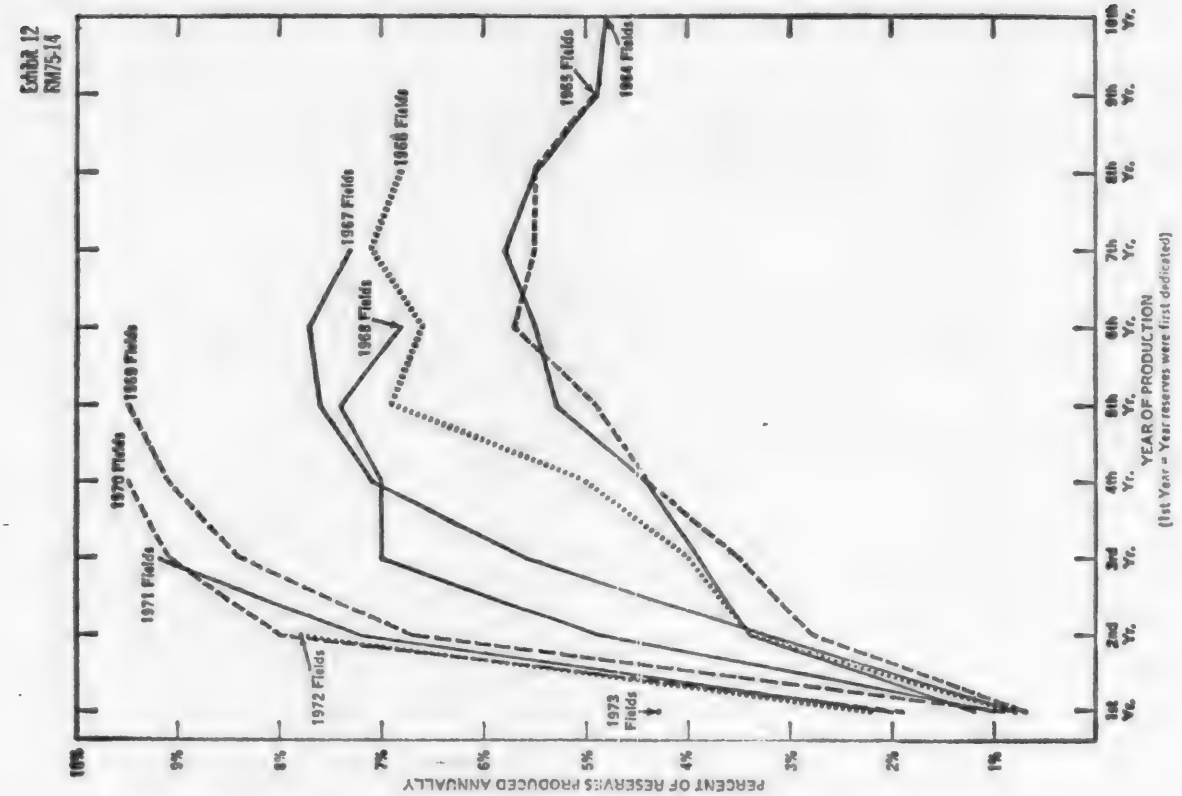
[142] Area Rate Proceeding (Permian Basin Area) 50 F.P.C. 390 (1973).

[143] Ibid. at 457. The rate finding in *Permian II*, however, is more consistent with an assumed 20-year life.

[144] Mimeo, p. 72.

[145] Id.

Docket No. RM75-14 - 70 -



					PRODUCTION FROM NEW FORM 15 FIELDS ADDED IN 1964				
A	82.	195.	240.	283.	386.	359.	360.	337.	277.	357.
R	1.2	3.4	3.9	4.4	5.3	5.5	5.8	5.5	4.9	4.8
	4834.	5661.	6091.	6385.	6843.	6496.	6185.	6117.	5630.	5331.
					PRODUCTION FROM NEW FORM 15 FIELDS ADDED IN 1965				
A		67.	330.	417.	540.	602.	717.	722.	719.	653.
R		0.7	2.8	3.5	4.4	4.9	5.7	5.5	5.5	4.9
		9485.	11789.	11931.	12225.	12317.	12648.	13209.	13010.	13324.
					PRODUCTION FROM NEW FORM 15 FIELDS ADDED IN 1966				
A			81.	352.	421.	561.	706.	647.	658.	615.
R			0.8	3.4	4.0	5.0	6.9	6.8	7.1	6.8
			9564.	10470.	10508.	11127.	10258.	9870.	9252.	8943.
					PRODUCTION FROM NEW FORM 15 FIELDS ADDED IN 1967				
A				70.	340.	562.	643.	662.	652.	579.
R				0.8	3.3	5.8	7.1	7.8	7.7	7.3
				8614.	10465.	10008.	9000.	8721.	8105.	7938.
					PRODUCTION FROM NEW FORM 15 FIELDS ADDED IN 1968				
A				64.	307.	429.	429.	440.	388.
R				1.0	4.9	7.0	7.0	7.4	6.8
				6288.	8318.	8108.	6114.	5977.	5724.
					PRODUCTION FROM NEW FORM 15 FIELDS ADDED IN 1969				
A					57.	451.	536.	561.	575.
R					0.9	6.7	8.4	9.1	9.5
					6216.	6718.	6401.	6202.	6083.
						PRODUCTION FROM NEW FORM 15 FIELDS ADDED IN 1970			
A						70.	303.	334.	349.
R						1.9	8.0	9.1	9.5
						3659.	3815.	3678.	3683.
							PRODUCTION FROM NEW FORM 15 FIELDS ADDED IN 1971		
A							44.	172.	219.
R							2.0	7.2	9.2
							2225.	2365.	2376.
								PRODUCTION FROM NEW FORM 15 FIELDS ADDED IN 1972	
A								113.	442.
R								2.2	7.8
								5040.	5644.
									PRODUCTION FROM NEW FORM 15 FIELDS ADDED IN 1973
A									74.
R									4.3
									1718.

A = Amount of annual production.
R = Gross reserves (plus remaining cumulative production).

Second, a study of 14 trillion cubic feet of offshore reserves by Witness Root for UDC indicates that the larger offshore fields (more than 400 Bcf) will be depleted in approximately 18 years and the smaller fields in 14 years. The pattern of field development that is indicated by the production rise and decline necessarily implies an average well life substantially less than the life of the entire field.[146]

Third, the "Optional Procedure" [147] cases that have been before the Commission involve more than 2.5 trillion cubic feet of reserves in such diverse areas as offshore Louisiana, onshore Louisiana, the Permian Basin, the Hugoton-Anadarko area and the State of Alabama. The evidence submitted by the producers in those proceedings estimated the well depletion periods typically at about ten years, never in excess of 17 years.[148]

Fourth, the evidence submitted in Docket No. RI75–112 contains detailed production patterns for approximately 140 reservoirs in the offshore area. The average reservoir life for those reserves is estimated by the producers to be between four and six years.[149] The reservoir life, of course, does not relate directly to well life because many wells, particularly in the offshore area, involve successive completions in a single well bore. Reservoir life is relevant to the present inquiry because recompletions into new reservoirs are treated as new wells for rate purposes.

Fifth, the evidence in the *IOGA* case involving 1,000 wells establishes accelerated early production even in the relatively low-permeability sands of the Appalachian area.[150] The average well life is 26 years, but 53 percent of the reserves are produced within the first five years and the composite production schedule has a present value equal to level production for less than 13 years.

Sixth, while IPR used the 699–H 18-year depletion life in its basic cost studies, its gathering study indicated that the weighted average life of the gathering systems, all of which were installed since January 1, 1970, to be 16.1 years.[151]

Seventh, UDC recommends a 15-year depletion period because such a period "would more nearly reflect anticipated future experience due to the need to maintain production of maximum levels to satisfy current needs." [152]

Finally, as the Commission noted in *Texas Gulf Coast* [153] "shortening of the (depletion) period is evidenced as the shortage of gas becomes more pronounced."

We find, therefore, that the available evidence establishes the necessity to reduce the assumed well-depletion period from the 18-year period. The 18-year period originated at a time when the more typical gas sales contract called for a daily production to reserve ratio of 1 : 7300 or a twenty-year life. Today, there is a continually worsening national shortage of gas in the interstate market and the more typical contract calls for minimum daily production of from 85% to 100% of the daily well capacity. The maximum rate of take of an average or typical well, of course, is much faster than a constant rate of take implied by an 18-year level production pattern.[154]

We find that a 15-year period for well depletion will more nearly conform both to the actual experience reflected by the evidence and to the need to encourage a relatively high deliverability from future wells.

We will continue to assume a level production for the 699–H model because the record does not reflect precise data from which the typical well depletion rate could be determined.

The OEC model is based upon a pattern of field or project development. In the application of that model we also shall use a 15-year well depletion period. There is, however, evidence from this and other proceedings that suggests patterns of production from fields as opposed to wells. The following graph (Exhibit 13) indicates the field production curve that was placed in evidence in *Permian I* [155] which is based upon a 37-year production life. That curve is, of course, heavily influenced by the onshore production and the moderate take levels of the pipelines prevalent at the time of Permian I. UDC submitted in this proceeding an analysis of the production schedule for 14 trillion cubic feet of offshore reserves with a field life of 18 years.[156] That also is charted. Since, in this proceeding, we must attempt to reach an average of all areas, we have attempted in the application of the OEC model to derive a hypothetical field production pattern that falls between the indicated onshore and offshore activity. We have made reasonable assumptions concerning well depletion rates and the rates of developmental drilling. The resultant production pattern is charted as the middle curve in Exhibit 13.

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[146] UDC Comments, July 24, 1975, Statement 8, Appendix A.

[147] 16 C.F.R. § 2.75.

[148] See Pennzoil Co., CI74–264, Direct Testimony of Engle, Schedule 7, Sheet 7. Also see, Forest Drilling Venture, CI75–40 and Coleve, CI75–538, wherein the producers estimated the life of 340 Bcf of offshore reserves to be 13 years.

[149] Docket No. RI75–112, Exhibit 258.

[150] Independent Oil and Gas Association of West Virginia, RI75–25, Direct Testimony of Louis J. Engel, Schedule No. 2.

[151] IPR Comments, May 30, 1975, Appendix N.

[152] UDC Comments, April 23, 1976, Statement 14, p. 17.

[153] Area Rate Proceeding (Texas Gulf Coast Area), 45 F.P.C. 674, 697 (1971).

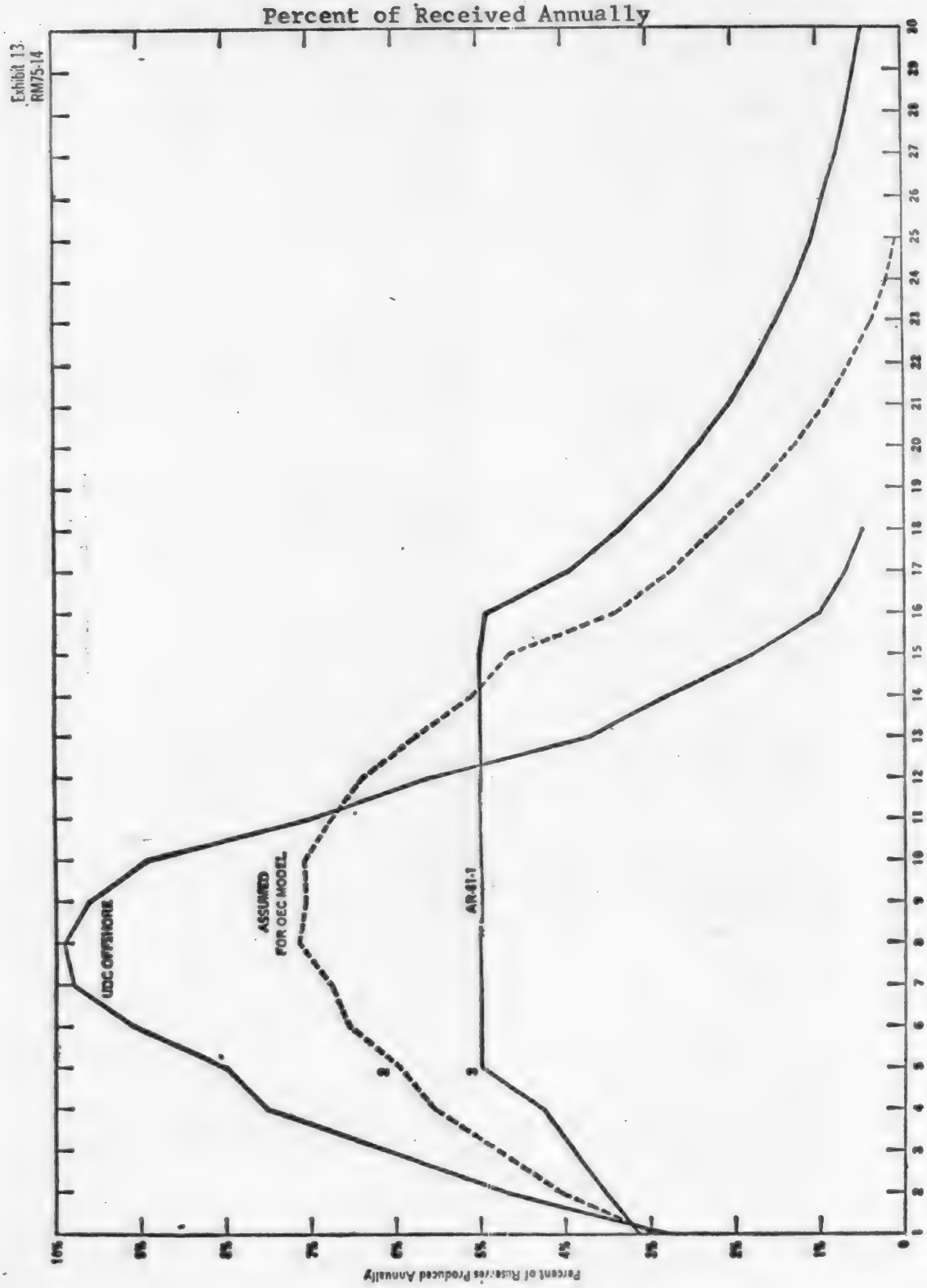
[154] See e.g., Area Rate Proceeding (South Louisiana Area), Docket No. AR69–1, Testimony of James Hicks, Tr. pp. 1891–1907, Exhibit 32.

[155] Supra, note ——.

[156] UDC Comments, July 24, 1975, Statement 8, Appendix A.

- 75 -

Percent of Received Annually



1. UDC Comments, July 8, 1975, Statement 8, Appendix A.
2. Exhibit 19 supra
3. Area Rate Proceeding (Permian Basin Area), Alt 61-1, TR. 14,580, 14,683 Exhibit 224, Schedule 10.

M. RATE OF RETURN

Among the initial comments filed in this proceeding, IPR submitted cost studies based upon a 17% rate of return that yielded a unit cost of $2.37 per Mcf.[157] On behalf of the Producers, Dr. Solomon recommended a rate of return in the range of 17% to 18% computed on a DCF basis after taxes. He stated that the rate of return should be increased to reflect the rise in utility bond rates from 1965 to the present and the increased risks accompanying new investments in gas production from deeper and more remote locations.[158] The GHK Company and Gas Anadarko Ltd. recommended a rate of return of at least 33% for wells drilled below a depth of 15,000 feet because of the high costs and risks associated with such drilling.[159]

Both BNG and OEC in their recommendations employed a 15% rate of return using the DCF methodology.[160] OEC pointed out that Opinion No. 699–H increased the effective rate of return by using a true rate of 15% rather than a nominal 15% rate on the average rate base. OEC further noted that inflationary expectations have moderated since the issuance of Opinion No. 699–H, which has the effect of raising the real rate of return over that implicit in the 15% nominal rate of return allowed in Opinion No. 699–H.[161]

In response to Staff recommendations, IPR stated that in calculating true yield on investment, BNG amortized investment on a unit of reserve basis over the productive life of the gas property which resulted in a declining annual revenue rate. It was argued that this rate design was contrary to the rate design of Opinion No. 699–H.[162] The Producers further argued that the 15% rate of return utilized by Staff was inadequate. UDC submitted cost studies using overall rate of return levels of 15% and 17% but without endorsement of either.[163]

The increasing rate of return allowed in the various area rate proceedings reflected the changing economic conditions. Where a 12% rate of return was found to be adequate in the first two area rate proceedings,[164] the higher cost of capital and the need for additional incentives to encourage greater investment in exploration and development programs resulted in the allowance of a 15% rate of return in the most recent area rate opinions.[165] In response to Dr. Solomon's comments we note that the 300 basis point increase in the allowed rate of return from the mid-1960's to the present approximately matches the rise in longterm interest rates over the same period.

In Opinion Nos. 699 and 699–H, the Commission adopted a comparative approach in determining a 15% rate of return, based upon the opportunity cost of capital concept. In that proceeding, the Commission determined that a 15% rate of return was comparable to the returns earned by other extractive industries, utility companies, industrial concerns, and the overall earnings of large integrated producers and the predominantly pure producer firms.[166]

More recently, in Opinion No. 749, we again used a 15% rate of return to establish the just and reasonable national rate for gas flowing prior to January 1, 1973.[167] In this opinion, however, less reliance was placed on the "comparative earnings" of the petroleum industry,[168] and greater emphasis was put on the comparison of returns on equity. Therein, we determined that a 15% overall rate of return yielded a 17.73% return on common equity while all industry groups examined showed returns on equity of 13.3% and 14.1% in 1972 and 1973, respectively.[169]

For these same reasons, we adopt the 15% overall rate of return employed in Opinion Nos. 699–H and 749. No evidence introduced in this proceeding is persuasive that a change in that judicially reviewed rate of return is now required or justified. The 15.00% overall return represents a 16.98% return on common equity[170] which is higher than that realized by most other industries examined, as reflected in Appendix C.

Although the 15% return on total capital as well as the equity returns under it are higher than the average returns realized by most industries, it is necessary to compare it with the returns necessary to attract new venture capital, rather than with the average established returns on combined total investment which involves a lower degree of risk. Unfortunately, we have no precise way of determining the marginal rates of return for new venture capital which are required for the average new natural gas project before funds will be invested. However, when all of the factors herein discussed are evaluated, the total return allowed by the Commission is within a permissible "zone of reasonableness."[171]

On that premise, it is our judgment that the 15% overall return is the appropriate incentive rate required to finance the exploration, development and production programs which must be undertaken to produce the new natural gas supplies necessary to fulfill the existing and future interstate demand.

However, we must account for the fact that the interest on the debt portion of the capital is deductible for tax purposes. Rather than computing the interest deductions throughout the production life of the property, we shall, for convenience, adopt the equivalent method of adjusting the computational rate of return to reflect the tax deductibility of interest costs. In implementing this approach, we have relied upon the most recent capital structure for the group of petroleum companies reported by Chase Manhattan Bank. This data reveals that a computational 14.16% rate will be the equivalent of 15% overall before consideration of the interest deductions.

EXHIBIT 14.—*Rate of return*[1]

(1) Type of financing	(2) Amount (millions of dollars)	(3) Composition (percent)	(4) Direct cost (percent)	(5) Direct weighted cost (percent)	(6) After-tax cost (percent)	(7) After-tax weighted cost (percent)
Long-term debt	25,591	21.81	[2] 8.00	1.75	[5] 4.16	0.91
Preferred equity	235	.20	[3] 8.25	0.02	8.25	0.02
Common equity	91,405	77.90	[4] 16.98	13.23	16.98	13.23
Total	117,331	100.00		15.00		14.16

[1] Alternate derivation:
(i) Overall return 15.00
(ii) Less interest on debt 1.75
(iii) Equity return 13.25
(iv) Tax on equity return $\left(13.25 \times \frac{.48}{.52}\right)$ 12.23
(v) Before tax return [(i)+(iv)] 27.23
(vi) After tax return [(v)×.52] 14.16

[2] Assumed; 1974 actual interest expense was $2,478 million on an average total short- and long-term debt of $32,047, implying an average rate of 7.7 pct. We adjust upward slightly to allow for refunding since 1974 at higher rates than embedded cost.
[3] Assumed.
[4] Implied allowance in setting 15-percent overall rate of return.
[5] After-tax cost equals Before-tax cost multiplied by (1.48), where .48 is the marginal tax rate.

Source: (2) "1974 Financial Analysis of a Group of Petroleum Companies," Chase Manhattan Bank, exhibit 9; (3)=(2)/total; (5)=(3)×(4); (7)=(3)×(6).

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[157] IPR Comments, May 30, 1975, Appendix L, Exhibit DWA–1, Schedule 1, Sheet 1.
[158] Ibid., Appendix H.
[159] Comments of the GHK Company and Gas Anadarko, Ltd., May 30, 1975, pp. 10–12.
[160] See Order Issuing Staff Recommendations, issued August 4, 1975.
[161] OEC Recommendation, May 30, 1975, p. 12.
[162] IPR Comments, September 5, 1975, Appendix A, p. 16.
[163] UDC Comments, May 14, 1975, Statement 7.
[164] Area Rate Proceeding, et al. (Permian Basin), 34 F.P.C. 159, 204 (1965); Area Rate Proceeding, et al. (Southern Louisiana Area), 40 F.P.C. 530, 576 (1968).
[165] Area Rate Proceeding, et al. (Other Southwest Area), 46 F.P.C. 900 (1971). The rates approved for the Other Southwest Area track the rates approved in *Southern Louisiana II* and *Texas Gulf Coast*, which were based upon a 15% rate of return.
[166] See Opinion No. 699, ____ F.P.C. ____, slip opinion at 61.
[167] See Opinion No. 749, ____ F.P.C. ____, slip opinion at 17.
[168] Less reliance was placed on the earnings of the petroleum industry for 1973 and 1974 due to the quadrupling of crude oil prices by the Organization of Petroleum Exporting Countries (OPEC) in late 1973 which caused an inordinate increase in earnings.
[169] See Opinion No. 749, supra, at 18.
[170] Ibid.
[171] *F.P.C. v. Natural Gas Pipeline Co.*, 315 U.S. 575, 585 (1942)

N. FEDERAL INCOME TAXES

Several parties have expressed concern over the treatment of Federal income taxes. In essentially identical initial comments filed on May 30, 1975, the Pennzoil Companies, the Rodman Corporation, Tenneco Oil Company and Texas Gulf, Inc. urged the Commission to provide an allowance for Federal income taxes in computing the new national base rate.

In Opinion Nos. 699 and 699-H, the Commission did not provide an allowance for Federal income taxes due to the absence of an evidentiary basis and its inability to hypothesize potential tax liabilities in a tax system that provided immediate write-off of intangibles and contained a percentage depletion allowance. Producers were considered to have no ascertainable income tax liability since those deductions were available as a deduction to offset income that would otherwise be taxable. Where producers sought special relief for Federal income taxes payable, the Commission referred producers to special relief procedures wherein submission of the appropriate tax returns would be required to establish the allowance for such taxes.[272]

The Staff in its recommendations issued in this proceeding stated that there was insufficient data for estimating the income tax liability of producers [273] and that it was impossible to evaluate the impact of the Tax Reduction Act of 1975 [274] on producer costs.[275] It was accordingly recommended that the Commission obtain an evidentiary basis to permit income tax estimation. In response to these recommendations, however, IPR, UDC, Pennzoil, Rodman, Tenneco, and Texas Gulf argued that no additional evidence was needed with respect to the rate impact of the elimination of percentage depletion on actual tax liabilities.

The Tax Reduction Act of 1975 amended the Internal Revenue Code as it applies to the exploration for and production of natural gas. This legislation effectively repealed percentage depletion for natural gas produced on or after January 1, 1975. Excepted from this repeal, however, were natural gas sold under a "fixed-price contract," [276] "regulated natural gas prior to July 1, 1976," [277] and specified quantities of natural gas sold by independent producers and royalty owners. Unlike most other provisions of that Act which were drafted to reduce taxes, the provisions dealing with percentage depletion were designed to increase the Federal income taxes paid by the petroleum industry.[278]

Subsequent to the enactment of this legislation, the Commission issued Opinion No. 749 [279] establishing a just and reasonable national rate for pre-January 1, 1973 gas supplies. In that opinion, the Commission made an allowance for increased Federal income taxes as of July 1, 1976 principally because of the repeal of precentage depletion. This allowance was based on the statutory rate of 48 percent [280] and resulted in an increment of 6.08 cents per Mcf.

As previously discussed, the costing models that we employ recognize the income tax deductions that are available to the producing industry at the earliest point at which the deduction may be taken under the Internal Revenue Code. The time value of the accelerated deductions that are available to the natural gas industry is thereby preserved for the benefit of the consumer. Of course, a deduction once taken is not again available to a taxpayer. Therefore, only the amount of the investment that is not "expensed" in the preproduction period is available to be recovered by cost depletion or depreciation during the productive life of the well or the property. The income tax deductions that are available during the production period thus consist only of the rather small annual depreciation item plus the additional ordinary and necessary business expenses, i.e., production, interest, and regulatory expenses.

We recently reviewed the legal authorities regarding income tax treatment of producers and concluded that the "regulated activities are properly viewed as a separate corporate entity and the Federal income tax allowance computed accordingly." [281] In this proceeding we have accounted for all income tax deductions and credits that are relevant to the exploration and development of natural gas that is jurisdictional to this Commission.[282] Once the appropriate deductions have been accounted for, the Internal Revenue Code specifically requires that an income tax be imposed upon the remaining income at the statutory rate for corporations—48% on income above $25,000.

Some have assumed that the natural gas producers will pay zero or very little tax, notwithstanding the repeal of the percentage depletion allowance. However, in the present context, that assumption can be founded upon only one underlying premise—that the industry in the future will expend a constantly increasing amount for exploration and development and that the increased level of intangible drilling cost deductions generated by those increased expenditures will be available to offset additional taxable income from the wells or projects that we are here costing.

Increases in gross exploration and development expenditures may be caused by either of two distinct phenomena: (1) increases in unit costs resulting either from general inflation or the "depleting resource" effect (the more scarce the resource the more expensive it is to find), or (2) increases in overall production reflective of a growing industry.

It is not necessary or appropriate to establish rates in this proceeding in reliance upon a projected increase in intangible drilling expense deductions if that projected increase is predicated upon a future increase in the unit cost of exploration and development. Those unit cost increases will be fully and properly accounted for in each subsequent biennial review.

In each successive review the full extent of an increase in income tax deductions that is generated by increasing unit costs will then be deducted from the gross investment in determining the rate. The net investment cost (hence the rate) for that future natural gas will be reduced accordingly. If we attempted to "capture" that future level of deductions in this proceeding, logic and fairness would require that the amount thus captured not be deducted once again in the future. The consequence would be a quagmire of calculus suitable only for an ethereal mathematician with a crystal ball. For present rate purposes, it is quite sufficient to recognize increased unit costs (and the income tax deductions generated thereby) at the time when the increase actually is realized. In addition, the taxable income from the natural gas wells that are drilled in this biennium provides a portion of the continuing justification for recognizing the full impact of the future deductions in the year in which the future investment is made.

Therefore, the only source of future income tax deductions that properly could

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[272] The Commission's treatment of Federal income taxes in those opinions was affirmed by judicial review. *Shell Oil Co., et al., v. F.P.C.*, 520 F. 2d 1061, 1080–1081 (5th Cir. 1975).

[273] See Comments of the Office of Economics, August 4, 1975.

[274] 89 Stat. 26, Pub. L. 94–12, § 401 adding § 613A to the Int. Rev. Code of 1954.

[275] See Comments of the Bureau of Natural Gas, August 4, 1975.

[276] Under § 613A(b)(2)(A) of the Code, "natural gas sold under a fixed-price contract" refers to gas sold by a producer under a contract in effect on or after February 1, 1975, under which the price cannot be adjusted to reflect the increased tax liability occasioned by repeal of the depletion allowjusted to reflect the increased tax liability ance. Price increases for such gas after February 1, 1975 are presumed to take the increased tax liability into account unless the taxpayer can prove otherwise.

[277] Under § 163A(b)(2)(B) of the Code, "regulated natural gas" refers to gas produced and sold by the producer before July 1, 1976 which is subject to the jurisdiction of the Commission, the price for which has not been adjusted to reflect the increased tax liability. Price increases for such gas after February 1, 1975 are presumed to take the increased tax liability into account unless the taxpayer can prove otherwise.

[278] See e.g., 121 Cong. Rec. H 1151–H 1161; H 1162; H 1163–H 1166; H 1168–H 1170; H 1171–H 1172; H 1177–H 1191 (February 27, 1975, daily ed.).

[279] Docket No. R–478, issued December 31, 1975.

[280] Int. Rev. Code of 1954, § 11.

[281] Opinion No. 749–C, issued July 19, 1976, mimeo. See also pp. 14–17.

[282] The foreign tax credit, for example, is not at all relevant to the producer activity that we directly regulate—the sale of natural gas in interstate commerce. We could not apply profits from foreign oil operations to reduce the price of domestic natural gas, nor could we do the same indirectly by appropriating tax credits that are traceable solely to the foreign operations.

be considered as potentially reducing taxes with respect to natural gas that we here price is deductions generated from real resources growth in the industry. Any such projection would be pure speculation. We of course anticipate that the industry will exhibit some growth as a result of the rate that we here establish, but precise quantification and allocation of the income tax consequences thereof is no more possible than precise estimation of the supply elasticity for natural gas. In any event, unless the United States Geological Survey (USGS) estimates of probable hydrocarbon reserves are extremely pessimistic, it would be incorrect to project a long term increase in the production of natural gas.

An additional reason for employing the full 48% tax rate, even if producers are not now paying an average rate that high, is that new supplies come from decisions to explore for and develop new fields. Marginal income therefrom is likely to be taxed at the 48% rate. Thus to employ any lower rate or extraordinary write-offs would be unrealistic. Therefore, a tax allowance based on the statutory rate has been included in our cost-based analysis, hereinbefore discussed, and is reflected in the rate prescribed.

Initial and reply comments were also submitted by several respondents with respect to the treatment of income taxes, seeking modification of the DCF methodology utilized in Opinion Nos. 699 and 699–H. These comments argued that the DCF costing models in that proceeding were inconsistent and discriminatory. For these same reasons, the Bureau of Natural Gas in its recommendations also suggested elimination of the negative income tax assumptions utilized in Opinion No. 699–H.[133] These comments and recommendations have been carefully considered and addressed in detail in the discussion of timing herein.[134]

O. ROYALTY

Royalty expenses represent the percentage of the gross receipts the producer must pay to the landowner for the privilege of extracting the gas from reserves underlying that land.

Opinion 699 adopted an allowance of sixteen percent to reflect increased royalty expenses, whereas prior Commission opinions employed an average royalty allowance of fifteen percent. Both BNG and OEC recommend retention of the 16 percent figure for the 1975–76 biennium. Those parties, who in their comments addressed the issue directly, proposed a royalty allowance of 17 percent.[135] We have previously considered some identical data and similar arguments and arrived at 15% royalty.[136] We believe it both reasonable and prudent to adopt the 16 percent allowance recommended by our staff.

The basis for this determination is our belief that the lower onshore royalty expense tends to reduce slightly that royalty expense incurred offshore. The Commission prices gas for a particular well either from the date the drilling or the sales commence, which is an approach that gives no consideration to the age of the lease that is being drilled. In view of the fact that many new onshore wells are drilled on existing leases which traditionally append only ⅛ royalty (12½%), it is reasonable to believe that the federal offshore royalty of 16⅔% is mitigated by the lower onshore rate.

Therefore, pending more reliable or convincing data we choose not to alter the 16% royalty allowance found to be just and reasonable in Opinion No. 699.

P. ESCALATION

While we have departed in this Opinion from the general objective of avoiding vintaging if possible, we still find this objective desirable and believe a properly constructed escalator might avoid the need for vintaging the 1975–1976 gas in subsequent biennial reviews. In periods of rising cost due to inflation and declining productivity, we would expect the rates for subsequent biennia to rise. If we failed to take that increase in rate into account in establishing the price for the current biennium, producers could earn in excess of the fair rate of return as the subsequent rates rose above those set in the previous biennial reviews.

Thus, we find it desirable to employ an escalator that takes future expected price increases into account. In order to avoid delayed drilling or dedication toward the end of each year in anticipation of escalation, we have decided to depart from the use of an annual escalator, and to use, instead, a quarterly escalator. We have chosen an escalator of 1.0¢ per quarter as a minimum escalator, implying a modest inflation in cost and some recovery in productivity with renewed exploratory drilling effort. The effect of this escalation is to move from a constant price of approximately 163¢/Mcf (based on the assumption that no further price increases are to be expected) to an escalating price beginning at 142¢/Mcf in 1976 and increasing by 4.0¢/Mcf in each succeeding year. The revenue stream with the escalator has the same present value as it would with a level price. In using an escalator, we are committed to permit the price of gas from wells drilled during the current biennium to escalate by at least the amount chosen here or its comparable present value so as to provide a 15% rate of return on investment. We therefore find that the escalator is an integral part of this rate.

Q. PRICE DETERMINATION

We have found that a productivity factor of 279 and 323 should be used to establish the upper and lower limits of the "zone of reasonableness." The prices resulting from these limits, derived below, are:

Model	With 4¢ escalator	
	279	323
699–H	154.1	131.3
OEC	153.5	131.0
Average	153.8	131.2

We thus find that the "zone of reasonableness" is 131¢ per Mcf for the low case and 154¢ per Mcf for the high case, each escalating at 4 cents annually.

1. The 699–H Model Applied

a. *279 Productivity.* The cost components and policy choices discussed above can now be brought together in the 699–H model of cost-based price determination.

Exhibit 15 consolidates the cost elements and tax effects to determine the after-tax cash flows. The percentage expensed for income tax purposes (intangibles) is the same as used in Opinion No. 699–H and in both the IPR and UDC and one BNG study. A 48% tax rate is used to compute the tax savings. A 10 percent investment tax credit is assumed taken in period −1 on the depreciable assets associated with successful well and production facilities outlays. Of the total gross outlays of 48.85¢/Mcf, 36.72¢/Mcf is expensed, resulting in a tax reduction in the pre-production period of 18.40¢/Mcf (including 0.78¢/Mcf investment tax credit) and after-tax cash flows totaling 30.45¢/Mcf.

EXHIBIT 15.—*Cost summary and tax treatment for 699–H model at 279 productivity*

[Cents per thousand cubic feet]

(1) Component	(2) Gross outlay	(3) Percent expensed	(4) Expensed amount	(5) Tax reduction from expensing	(6) Net cash flow	(7) Time
Working capital	1.43	0	0	0	1.43	−3
Exploratory other	5.06	95	4.83	2.32	2.76	−2
Exploratory O/H	1.84	95	1.75	0.84	1.00	−3
Lease acquisition	15.19	0	0	0	15.19	−2
Nonproducing lease expensed	0	75	11.39	5.47	(5.47)	−1
Dry hole	8.75	100	8.73	4.19	4.54	−1
Successful well	13.81	70	9.67	4.64	9.17	−1
Production facilities	3.70	0	0	0	3.70	−1
Recompletion	0.50	70	0.35	0.17	0.33	−1
Investment tax credit	0	0	0	0.78	(0.78)	−1
Working capital recovery	(1.43)	0	0	0	(1.43)	14
Total	48.85		36.72	18.40	30.45	

NOTE.—Depreciable or depletable assets: 48.85−36.72=12.13; investment tax credit: .10×(13.81−9.67+3.70)=0.78; present value at time 0 of net cash flows at 14.16 pct: 40.42; present value at time 0 of net cash flows at 14.16 pct allocated to natural gas production: 0.91×40.42=36.78 (4)=(2)×(3); (5)=(4)×.48; and (6)=(2)−(5).

[133] See Opinion No. 699–H, Appendix C, pp. 6 and 7.
[134] Section III. A., *supra.*
[135] IPR comments, May 30, 1975, Appendix B, p. 14.
[136] Area Rate Proceeding (South Louisiana Area), 46 F.P.C. 86, 132–3 (1971).

Using the 699–H timing sequence outlined in Exhibit 1, supra, and a 14.16% [187] rate of return, the present value at year 0 of the after-tax cash flows is 40.42¢/Mcf. Taking 91% of this cost as the share allocatable to natural gas production [188] results in a present value cost of 36.78¢/Mcf.

Exhibit 16 displays the after-tax cash flows resulting from the sale of 1 Mcf with a 16% royalty rate, 91 percent cost allocation and a 48% tax rate. At a price of P cents per Mcf, the after-tax cash flow is (.4368P+3.79) ¢ per Mcf.

[187] This is the computational rate that equals a 15% overall return adjusted to reflect interest deduction. See p. 80, supra.

[188] See Cost Allocation, pp. 64–66, supra.

EXHIBIT 16.—*Cash flow from sales (cents per thousand cubic feet) at 279 Mft*[3]

Price		P
Royalty		.16P
Net revenue		.84P
Less:		
Operating expenses	3.10×.91= 2.82	
Regulatory expenses	.10×.91= .09	
Depreciation	12.13×.91=11.04	13.95
Income before taxes		.84P−13.95
Taxes at 48 percent		.4032P− 6.70
Net income		.4368P− 7.25
Add:		
Depreciation		11.04
After-tax cash flow		.4368P+ 3.79

The price determining process is to equate present value of the cash flows from the cost items to the present value of the cash flows from the sales. The present value of a dollar per year for 15 years starting at time 0 is

$$\sum_{t=0}^{14}(1.1416)^{-t}=6.9562;$$

the present value of the cash flows from the sale of $\frac{1}{15}$ Mcf per year for the 15 year period from 0 through 14 is

$$\frac{1}{15}\times 6.9562\times(.4368P+3.79)=.2026P+1.758$$

Equating this to the pesent value of the cost items results in a constant price of

$$.2026P+1.758=36.78$$

or

$$P=172.9¢ \text{ per Mcf.}$$

As we indicated earlier, we find that 4¢ per year escalator is appropriate. Since the present value of a 1¢ escalator, adjusted for income tax and royalty, is 0.948¢, i.e.,

$$\frac{1}{15}\sum_{t=0}^{14}t(1.1416)^{-t}(.52)(.84)=.948¢,$$

using a 4¢ per year escalator results in a base year price of P_o, where P_o is such that

$$.2026P_o+1.758+.948(4)=36.78$$

or

$$P_o=154.1¢ \text{ per Mcf}$$

Thus the 699-H/cost-based price is 154.1¢/Mcf beginning in 1976 and escalating at 4¢ per annum.

b. *323 Productivity.* Exhibits 17 and 18 are patterned after Exhibits 15 and 16 but with cost and revenue computations based upon a 323 Mcf productivity. Equating the present value of the cost items to the present value of the revenue stream we find a constant price of

$$\frac{1}{15}\times 6.9562\times(.4368P+3.08)=.2026P+1.428=31.82$$

or

$$P=150.0¢ \text{ per Mcf}$$

With a 4¢ per annum escalator, the base year price of P_o is

$$.2026P_o+1.428+.948(4)=31.82$$

or

$$P_o=131.3¢ \text{ per Mcf.}$$

EXHIBIT 17.—*Cost summary and tax treatment for 669–H model at 323 Mft*[3]

[Cents per thousand cubic feet]

(1) Component	(2) Gross value	(3) Percent expensed	(4) Expensed amount	(5) Tax reduction from expensing	(6) Net cash flow	(7) Time
Working capital	1.24	0	0	0	1.24	−3
Exploratory other	4.30	95	4.17	2.00	2.30	−3
Exploratory O/H	1.50	95	1.51	.72	.86	−3
Lease acquisition	13.12	0	0	0	13.12	−2
Nonproducing lease expensed	0	75	9.84	4.72	(4.72)	−1
Dry hole	7.54	100	7.54	3.62	3.92	−1
Successful well	11.93	70	8.35	4.01	7.92	−1
Production facilities	3.20	0	0	0	3.20	−1
Recompletion	.50	70	.35	.17	.33	−1
Investment tax credit	0	0	0	.68	(.68)	−1
Working capital recovery	(1.24)	0	0	0	(1.24)	14
Total	42.27		31.76	15.93	26.34	

NOTE.—Depreciable or depletable assets: 42.27−31.76=10.51; investment tax credit: .10×[(11.93−8.35)+3.20]=.68; present value at time 0 of net cash flows at 14.16 percent: 34.97; present value at time 0 of net cash flows at 14.16 percent allocated to natural gas production: 0.91×34.97=31.82; (4)=(2)×(3); (5)=(4)×.48; and (6)=(2)−(5).

EXHIBIT 18.—*Cash flow from sales (cents per thousand cubic feet) at 323 Mft*[3]

Price		P
Royalty		.16P
Net revenue		.84P
Less:		
Operating expenses	3.10×.91=2.82	
Regulatory expenses	.10×.91= .09	
Depreciation	10.51×.91=9.56	12.47
Income before taxes		.84P−12.47
Taxes at 48 percent		.4032P− 5.99
Net income		.4368P− 6.48
Add:		
Depreciation		9.56
After-tax cash flow		.4368P+ 3.08

2. *The OEC Model Results*

a. *Project Development and Rates of Take.* Unlike the 699–H model, which costs the average successful well drilled during the test year, the OEC model is based upon the full development of a field or project, from preliminary geological and geophysical activities to shutdown.

As discussed in Section III.L, supra, we find it reasonable to assume a fifteen year life for a well, with declining rates of take for the well over time. In order to arrive at a field rate of take which falls between the limits set forth in Exhibit 13, we find that a developmental period of 10 years, with steadily declining rates of developmental drilling activity, is a reasonable assumption. Exhibit 19 displays the results of these assumptions in terms of the production of 3.36 Mcf over a 25 year field life.

Exploratory drilling, which alone yields 1 Mcf of ultimate recovery for every 3.36 of ultimate recovery from the field, is done in year −1 with production spread over the 15 years, denoted years 0 through 14. Developmental drilling, resulting in an additional 2.36 Mcf, takes place over the next 10 years, 0 through 9. Reserves from developmental drilling produce for fifteen years, following the same rate of take as applied to the exploratory well. The resultant total annual production, as set forth in the next to the last column of Exhibit 19, sums to 3.36 Mcf over the 25 year period. Dividing annual production by 3.36 results in the rate of take curve for the field found in the last column of Exhibit III and plotted as the curve No. 2 in Exhibit 13.

b. *279 Productivity.* The OEC model has preproduction exploratory expenditures in the same time sequence as the 699–H model previously described. The developmental drilling expenditures, however, are spread over 10 years, in the proportions set out at the bottom of Exhibit 19. The resultant outlays and their timing are found in Exhibit 20.

The exploratory outlays of Exhibit 20 are based upon exploratory activity which is assumed to produce 1 Mcf ultimate recovery from exploratory wells and leads to 3.36 ultimate recovery from the field through subsequent developmental drilling. Thus, the exploratory expense items, Exploratory Other, Exploratory Overhead, and Lease Acquisition are entered at 3.36 times the values used in the 699–H model as set forth in Exhibit 15 (slight differences are due to rounding).

Exploratory and developmental successful well and dry hole costs are as determined in Section III.C., supra. Production Facilities and Recompletion costs are the same per Mcf as used in the 699–H model.

The present value at time 0 using the computational discount rate of 14.16% of the after-tax cash flows from the exploratory cost outlays detailed in Exhibit 20 is 81.66¢, including the related investment tax credit assumed taken in year −1.

Assuming a 4 percent rate of inflation on developmental drilling costs beginning in year 1, and using the developmental Mcf production totals found in Exhibit 19 in conjunction with the cost per Mcf for developmental activity from Exhibit 20, the present value of the after-tax cash flows associated with the developmental costs of the field is 30.94¢, including investment tax credit considerations (also escalating at 4% per year).

Working capital is 3.36 times that employed in the 699–H model application, but spread over 28 rather than 18 years. Thus,

$$\text{working capital} = 1.43 \times 3.36 \times \frac{18}{28} = 3.09¢.$$

Exhibit 19

Mcf Production

Year	Year of Drilling											Total Annual Prod.	Rate of Take
	-1	0	1	2	3	4	5	6	7	8	9		
0	0.1000	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1000	0.0298
1	0.1000	0.0354	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1354	0.0403
2	0.0900	0.0354	0.0330	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1584	0.0472
3	0.0900	0.0319	0.0330	0.0307	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1856	0.0552
4	0.0800	0.0319	0.0297	0.0307	0.0283	0.0	0.0	0.0	0.0	0.0	0.0	0.2006	0.0597
5	0.0800	0.0283	0.0297	0.0276	0.0283	0.0260	0.0	0.0	0.0	0.0	0.0	0.2199	0.0655
6	0.0700	0.0283	0.0264	0.0276	0.0255	0.0260	0.0236	0.0	0.0	0.0	0.0	0.2274	0.0677
7	0.0700	0.0248	0.0264	0.0245	0.0255	0.0234	0.0236	0.0212	0.0	0.0	0.0	0.2394	0.0713
8	0.0600	0.0248	0.0231	0.0245	0.0227	0.0234	0.0212	0.0212	0.0165	0.0	0.0	0.2375	0.0707
9	0.0600	0.0212	0.0231	0.0215	0.0227	0.0208	0.0212	0.0191	0.0165	0.0118	0.0	0.2379	0.0708
10	0.0500	0.0212	0.0198	0.0215	0.0198	0.0208	0.0189	0.0191	0.0149	0.0118	0.0094	0.2272	0.0676
11	0.0500	0.0177	0.0198	0.0184	0.0198	0.0182	0.0189	0.0170	0.0149	0.0106	0.0094	0.2147	0.0639
12	0.0400	0.0177	0.0165	0.0184	0.0170	0.0182	0.0165	0.0170	0.0132	0.0106	0.0085	0.1936	0.0576
13	0.0300	0.0142	0.0165	0.0153	0.0170	0.0156	0.0165	0.0149	0.0132	0.0094	0.0085	0.1711	0.0509
14	0.0300	0.0106	0.0132	0.0153	0.0142	0.0156	0.0142	0.0149	0.0116	0.0094	0.0076	0.1565	0.0466
15	0.0	0.0106	0.0099	0.0123	0.0142	0.0130	0.0142	0.0127	0.0116	0.0083	0.0076	0.1142	0.0340
16	0.0	0.0	0.0099	0.0092	0.0113	0.0130	0.0118	0.0127	0.0099	0.0083	0.0066	0.0927	0.0276
17	0.0	0.0	0.0	0.0092	0.0085	0.0104	0.0118	0.0106	0.0099	0.0071	0.0066	0.0741	0.0221
18	0.0	0.0	0.0	0.0	0.0085	0.0078	0.0094	0.0106	0.0083	0.0071	0.0057	0.0573	0.0171
19	0.0	0.0	0.0	0.0	0.0	0.0078	0.0071	0.0085	0.0083	0.0059	0.0057	0.0432	0.0129
20	0.0	0.0	0.0	0.0	0.0	0.0	0.0071	0.0064	0.0066	0.0059	0.0047	0.0307	0.0091
21	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0064	0.0050	0.0047	0.0047	0.0208	0.0062
22	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0050	0.0035	0.0038	0.0123	0.0037
23	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0035	0.0028	0.0064	0.0019
24	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0028	0.0028	0.0008
Total	1.0000	0.3540	0.3304	0.3068	0.2832	0.2596	0.2360	0.2124	0.1652	0.1180	0.0944	3.3600	1.0000
Fraction of Developmental Outlays		.15	.14	.13	.12	.11	.10	.09	.07	.05	.04		

EXHIBIT 20.—*OEC cost summary and tax treatment at 279 productivity*

[Cents per thousand cubic feet]

(1) Exploratory costs [1]	(2) Gross	(3) Percent expensed	(4) Expensed amount	(5) Tax reduction from expensing	(6) Net cash flow	(7) Time
Exploratory O/H (cents per 3.36 Mft³)	6.17	95	5.86	2.82	3.36	−3
Exploratory other (cents per 3.36 Mft³)	17.08	95	16.22	7.79	9.29	−3
Lease acquisition (cents per 3.36 Mft³)	51.04	0	0	0	51.04	−2
Nonproducing lease expensed	0	75	38.28	18.38	(18.38)	−1
Dry hole (cents per thousand cubic feet)	17.35	100	17.35	8.33	9.02	−1
Successful well (cents per thousand cubic feet)	4.41	70	3.09	1.48	2.93	−1
Production facilities (cents per thousand cubic feet)	3.70	0	0	0	3.70	−1
Total	99.75		80.81	38.79	60.97	
Developmental (cents per thousand cubic feet): [2]						
Successful wells	17.76	70	12.43	5.97	11.79	0-9
Dry hole	5.22	100	5.22	2.50	2.71	0-9
Production facilities	3.70	0	0	0	3.70	0-9
Recompletion	.50	70	.35	.17	.33	0-9
Total	27.18		18.00	8.64	18.53	

[1] Depreciable or depletable assets: 99.75−80.81=18.94; investment tax credit: .10(4.41−3.09+3.70)=0.50; present value at time 0 of net cash flows at .1416=81.66.

[2] Depreciable or depletable assets: 27.18−18.00=9.18; investment tax credit: .10(17.76−12.43+3.70)=0.90; present value at year 0 of net cash flows at .1416=30.94.

NOTE.—(4)=(2)×(3); (5)=(4)×.48; (6)=(2)−(5).

Exhibit 21 summarizes the present value of the after-tax cash outflows from the cost components. A present value at time 0 of 106.52¢ is required to produce 3.36 Mcf of natural gas after total costs have been allocated between gas production and liquids.

EXHIBIT 21.—AFTER-TAX CASH OUTLAYS AT 279 PRODUCTIVITY (CENTS PER M FT.³)

Cost component:	*Present value at 14.16% at time=0*
Exploratory outlays	81.66
Developmental outlays	30.94
Working capital:	
Outlay in −3 of 3.09	4.59
Recovery in +24 of 3.09	(0.13)
Total present value in time=0	117.06
Allocation factor (multiplied by)	.91
Present value of cost item Cash flows (cents per 3.36 M ft³)	106.52

The present value at time zero of the production of 3.36 Mcf according to the rate of take given in Exhibit 19, using a 14.16% discount rate, is 1.3015 Mcf. Thus, at a price per Mcf of P, with a 16% royalty rate, allocated operating costs of 2.82¢ per Mcf and allocated regulatory expense of 0.09¢/Mcf, the present value of the after-tax cash flows from the sale of 3.36 Mcf over the 25-year production life of the field (exclusive of the tax savings from depreciation) is

$$(.84P-2.82-.09)\times.52\times1.3015=.5685P-1.9694$$

Further analysis would show that the present value of the tax saving arising from the depreciation charges of the tangibles is 8.03¢ per 3.36 Mcf.

Equating the present value of the cost item outlays with the present value of the after-tax cash flows from sales, results in a constant price of

$$.5685P-1.9694+8.03=106.52$$

or

$$P=176.7¢ \text{ per Mcf}$$

Including the effect of a 4¢ escalator per year reduces the base-year price. In this case, the present value of a 1¢ escalator is 3.292¢ (somewhat higher than 3.36 times the 699–H case, since the rate of take is faster in the OEC model). Using a 4¢ escalator we find the base year cost-justified price to be:

$$.5685P-1.9694+8.03+3.292(4)=106.52$$

or

$$P=153.5¢ \text{ per Mcf}$$

Thus, the OEC cost-based price is 153.5¢ per Mcf beginning in year 1976 and escalating at 4¢ per year.

c. *323 Productivity.* Exhibits 22 and 23 are patterned after Exhibits 20 and 21 but with cost computations based upon a 323 Mcf productivity. The present value of the revenue stream is

$$(.84P-2.82-.09)\times.52\times1.3015=.5685P-1.9694$$

With the present value of the tax savings arising from depreciation charges of the tangibles at 6.956¢ per 3.36 Mcf, the equating of the present value of revenues with costs leads to a constant price of

$$.5685P-1.9694+6.956=92.61$$

or

$$P=154.1¢ \text{ per Mcf}$$

Using a 4¢ escalator results in a base year cost-justified price of:

$$.5685P_o-1.9694+6.956+3.292(4)=92.61$$

or

$$P_o=131.0¢ \text{ per Mcf}$$

EXHIBIT 22.—*OEC cost summary and tax treatment at 323 productivity*

[Cents per thousand cubic feet]

(1) Exploratory costs [1]	(2) Gross outlays	(3) Percent expensed	(4) Expensed amount	(5) Tax reduction from expensing	(6) Net cash flow	(7) Time
Exploratory O/H (cents per 3.36 Mft [3])	5.33	95	5.07	2.43	2.90	−3
Exploratory other (cents per 3.36 Mft [3])	14.75	95	14.01	6.73	8.02	−3
Lease acquisition (cents per 3.36 Mft [3])	44.09	0	0	0	44.09	−2
Nonproducing lease expensed	0	75	33.07	15.87	(15.87)	−1
Dry hole (cents per thousand cubic feet)	15.80	100	15.80	7.58	8.22	−1
Successful well (cents per thousand cubic feet)	4.01	70	2.81	1.35	2.66	−1
Production facilities (per thousand cubic feet)	3.20	0	0	0	3.20	−1
Total	87.18		70.75	33.96	53.22	
Developmental (cents per thousand cubic feet) : [2]						
Successful well	15.29	70	10.70	5.14	10.15	0-9
Dry hole	4.49	100	4.49	2.16	2.34	0-9
Production facilities	3.20	0	0	0	3.20	0-9
Recompletion	.50	70	.35	.17	[illegible]	0-9
Total	23.48		15.54	7.46	16.02	

[1] Depreciable assets: 87.18−70.75=16.43; investment tax credit: .10[4.01−2.81+3.20]=0.44; present value at time 0 of net cash flows at 14.16 pct: 71.16.

[2] Depreciable assets: 23.48−15.54=7.93; investment tax credit: .10(15.29−10.70+3.20)=0.78; present value at time 0 of net cash flows at 14.16 pct: 26.74.

NOTE.—(4)=(2)×(3); (5)=(4)×.48; (6)=(2)−(5).

Exhibit 23.—After-Tax Cash Outlays at 323 Productivity (cents per M ft³)

Cost component:	*Present value at 14.16% at time=0*
Exploratory outlays	71.16
Developmental outlays	26.74
Working capital:	
Outlay in −3 of 2.68	3.99
Recovery in +24 of 2.68	(0.11)
Total present value at time =0	101.77
Allocation factor (multiplied by)	.91
Present value of cost item cash flows (cents per 3.36 M ft³)	92.61

IV. RATE DETERMINATION FOR 1973–1974 VINTAGE GAS

The current price for natural gas of the 1973–1974 vintage, as established in Opinion No. 699–H, is 52 cents per Mcf. That price was established without the benefit of actual drilling cost data for 1973 or 1974, and without reserves added data for 1973 and 1974, included in the rate determination and before enactment of the Tax Reduction Act of 1975. Subsequently, the data revealed dramatic increases in costs between 1973 and 1974, and continued declines in average productivity. Current and future production of that gas will not receive the benefits of percentage depletion and, therefore, future income from the sale of that gas will be subject to a greater income tax than the treatment provided in Opinion No. 699–H.

Thus, while we "vintage" the gas of the 1973–74 biennium so as to preclude it from receiving the 1975–1976 new gas rate, we must adjust the 699–H price to reflect those changing factors.

To develop the adjusted costs we adopt the following changes:

Productivity.—In Opinion No. 699–H the Commission based the rate upon a seven-year average for the years 1966–1972 and a consequent estimated productivity factor of 485 Mcf per foot. We update that estimate by including in the underlying series the reserves data for 1973 and 1974 and derive a lower productivity of 373 Mcf per foot.[190]

Drilling Costs.—We find the average of 1973 and 1974 drilling costs to be appropriate. The average successful well cost was $30.71 per foot and the average dry-hole cost was $22.60 per foot. These figures are higher than the $29.83 successful well and $16.69 dryhole cost estimates used in Opinion No. 699–H.

Finally, we employ the 15-year depletion period, the tax treatment and the computational rate of return used in determining the 1975–1976 new gas rate. Otherwise, all parameter and cost estimates follow Opinion No. 699–H as summarized in Appendix C of that opinion. The cost component derivations are displayed in Exhibit 24, herein.

[190] Exhibit 2, supra.

EXHIBIT 24.—COST COMPONENTS FOR 1973–74 VINTAGE GAS

[Cents per thousand cubic feet]

Successful wells	8.23 = 30.71 ÷ 373.
Recompletion and deeper drilling [1]	0.20.
Lease acquisition	5.73 = 8.23 × .6957.
Other production facilities	1.86 = 8.23 × 0.226.
Subtotal	16.02
Dry holes	6.54 = 22.60 × 1.08 ÷ 373.
Other exploration	3.75 = 5.73 × .6546.
Exploration overhead	1.31 = (6.54 + 3.75) × 0.127.
Subtotal	11.60
Operating expense	3.10
Regulatory expense	0.20
Net liquid credit	(3.89)
Working capital	0.75 {[(11.60 × 1.336) + (3.10 × 1.689)] .125 + (5.73 × 1.5)}/15.

NOTE.—Computational rate of return, 14.16 percent.

[1] Opinion No. 662.

Exhibits 25 and 26 are patterned after Exhibits 15 and 16, but with cost and revenue computations based upon the cost components displayed in Exhibit 24. Equating the present value of the cost items to the present value of the revenue stream, we find a constant price of

$$\frac{1}{15 \times (6.9562) \times (.4368P + 3.23)} = 21.99$$

or

$$P\ 101.2$$

We therefore judge the just and reasonable rate for the 1973–74 vintage gas to be 101¢ per Mcf.

EXHIBIT 25.—*Cost summary and tax treatment for 1973–74 vintage gas*

(1) Component	(2) Gross value	(3) Percent expensed (cents per thousand cubic feet)	(4) Expensed amount	(5) Tax reduction from expensing	(6) Net cash flow	(7) Time
Exploratory other	3.75	95	3.56	1.71	2.04	−3
Exploratory O/H	1.31	95	1.24	.60	.71	−3
Lease acquisition	5.73	0	0	0	5.73	−2
Nonproducing lease expensed	0	75	4.30	2.06	(2.06)	−1
Dry hole	6.54	100	6.54	3.14	3.40	−1
Successful well	8.23	70	5.76	2.77	5.46	−1
Production facilities	1.86	0	0	0	1.86	−1
Recompletion	.20	70	.14	.07	.13	−1
Investment tax credit	0	0	0	.30	(.30)	−1
Working capital	.75	0	0	0	.75	−1
Working capital recovery	(.75)	0	0	0	(.75)	14
Total	27.62		21.54	10.65	16.97	

NOTE.—Depreciable or depletable assets: 27.62 − 21.54 = 6.08; investment tax credit: .07 × [(8.23 − 5.76)] + 1.86] = .30 present value at time 0 of net cash flows: 21.99.

EXHIBIT 26.—*Cash flow from sales for 1973–74 vintage gas*

[Cents per thousand cubic feet]

Price			P
Royalty			.16P
Net revenue			.84P
Less:			
Operating expenses		3.10	
Regulatory expenses		.20	
Depreciation		6.08	
Liquid credit	(3.89)		5.49
Income before taxes			.84P − 5.49
Taxes at 48 percent			.4032P − 2.64
Net income			.4368P − 2.85
Add depreciation			6.08
After tax cash flow			.4368P + 3.23

V. NON-COST FACTORS

As was pointed out in our earlier discussion of cost methodology, a careful examination of costs and revenues associated with the various facets of producer activities is essential in determining a just and reasonable rate. However, it is also important to consider this cost-based price in relation to other economic factors, including market values, inflation, supply and demand, and the costs of alternative fuels. In *Mobil Oil Corporation* v. *F.P.C.*, 417 U.S. 283, 301, the Court noted that the Natural Gas Act provides for the setting of rates equal to the utilities' cost of service plus a reasonable rate of return. The Court went on to state, however, that the Act is not limited only to the concept of cost plus a reasonable rate of return.[190] Accordingly, we utilize a cost-based rate determination as the foundation for our ratemaking function, but we examine the non-cost elements in an economic framework to insure that the "end result" is just and reasonable.[191]

In the *Permian Basin Area Rate Proceeding*,[192] the Commission first used an experimental costing methodology to establish maximum and minimum rates for an entire gas producing area. This same methodology was again the basis in Opinion No. 699 in initiating a nationwide rate. Although the Supreme Court affirmed the Commission's *Permian* decision in full,[193] the Court noted that the Commission made no assessment of the effect of its prices on supply, demand, reserves or industry structure. The Supreme Court advised that in future cases the Commission should state more "fully and carefully . . . its assessment of the consequences of its orders for the character and future development of the industry." [194] Furthermore, the Court unequivocally stated that the Commission is not bound by the sum of cost and return even if it adopts cost as the primary basis of the calculations.[195]

Similarly, in affirming the Commission's decision in the *Southern Louisiana Area Rate Cases* (Austral),[196] the Court of Appeals found that the need for dramatically increased production justified the inclusion of non-cost factors, and that the Commission had the power to include non-cost elements that reflect its assessment of the need to use price as a tool to influence such economic rela-

[190] 417 U.S. at 316.

[191] *FPC* v. *Hope Natural Gas Company*, 320 U.S. 591 (1944).

[192] 34 F.P.C. 159.

[193] *In Re Permian Basin Area Rate Cases*, 390 U.S. 747, 88 S. Ct. 1344 (1968).

[194] *Id.*, 390 U.S. at 792, 88 S. Ct. at 1373.

[195] *Id.*, 390 U.S. at 815, 88 S. Ct. at 1385 and nn. 97–99.

[196] *Southern Louisiana Area Rate Cases* v. *F.P.C.*, 428 F.2d 407 (1970).

tions.[197] Although the Commission's area rate decision was affirmed, the Court of Appeals noted the Commission's failure to approach supply and demand, and other non-cost factors, in either a semi-quantitative or qualitative fashion.[198] In conclusion the Court said that in the future the Commission must estimate the needs of consumer service, explain how that level of service is related to actual demand, and then fix a rate stating how it will affect the industry's tendency to meet that level of service.[199]

In the reopened *Southern Louisiana Rate Proceedings*, the Commission issued Opinion No. 598[200] in which it noted that "[we] would be derelict . . . if we were to be guided by the legalism of the past in seeking solutions to the problems which have grown like barnacles as this case has aged and its size has mounted."[201] In affirming the Commission's opinion, the Court of Appeals observed that the overriding objective of the Commission was to adopt "a total rate structure to motivate private producers to fully develop resources."[202]

The most recent decision of the Supreme Court, with respect to the consideration of non-cost factors, occurred in *F.P.C.* v. *Conway Corp.*, No. 75-342 (June 7, 1976). There, the Court found that the Commission must consider regulated non-jurisdictional retail rates in establishing wholesale rates for jurisdictional electric utilities. The Court noted that "consideration of the relationship between jurisdictional and non-jurisdictional rate structure is commonplace, and is nothing more than is required by *Colorado Interstate Co.* v. *Commission*, 324 U.S. 581 (1945), and by *Panhandle Co.* v. *Power Commission*, 324 U.S. 635 (1945)."

In Opinion No. 699, the Commission noted the Austral requirements[203] that non-cost factors such as the effect of the new national rate upon supply and demand be considered.[204] The producers, however, objected to the cost-based methodology employed, and argued that other non-cost factors such as the "commodity value" of natural gas should have been considered.[205] In affirming the Commission's opinion,[206] the Court rejected this argument stating that the "approved practice of basing rates on cost carries a substantial presumption of validity."[207] Consequently, the Commission can hardly abandon its traditionally cost-based methodology, i.e. that costs must be the point of departure in arriving at a just and reasonable rate, *City of Detroit*, v. *F.P.C.*, 230 F. 2d 810 (CADC 1955) cert. denied, 352 U.S. 829, in the absence of legislative action or judicial mandate.

At the same time, the Natural Gas Act requires examination of a broad spectrum of economic factors. *Colorado Interstate Gas Co.* v. *F.P.C.*, 324 U.S. 581, 605. The Supreme Court has held that the total effect of the rate order must be just and reasonable. *F.P.C.* v. *Hope Natural Gas Co.*, 320 U.S. 591 (1944). Thus, we will build upon evidence that supports a just and reasonable cost-based rate determination, and go on to consider its relationship to such non-cost factors as commodity value, inflationary impact, and supply and demand effects.

A. INTRASTATE MARKETS

The regulation of the price of natural gas was based on the premise that workable competition does not exist in the gas-producing industry. If this premise is true, then observed prices in unregulated markets will be higher than would prevail under competitive conditions. Others contend that in the absence of barriers to entry, production is competitive.

We have been mindful of these opposite views in factoring in the price of gas in the unregulated intrastate markets into our price determination.

Intrastate prices have risen dramatically over the past few years, as the prices reported in Exhibit 27 indicate. The most recent average intrastate price is 1.55¢/Mcf for the first quarter of 1976. Since a competitive market price tends toward the cost of producing the good or service in question, insofar as the intrastate markets are competitive, this price indicates a cost-based price for natural gas. The price we set with this opinion is somewhat lower than that of many recent intrastate prices. The differential may be due to a lack of workable competition in those markets or supply/demand imbalance in those markets that results in the current price not being that which would prevail in long-run equilibrium.

We are also mindful that there is some reluctance upon the part of producers to permanently dedicate fields to the interstate market. Such a long-term commitment carriers a cost that must be borne. We take this into account in establishing the rates herein.

[207] *Id.*, slip opinion at 185.

EXHIBIT 27.—*Intrastate prices*

[Cents per thousand cubic feet]

	1975		1976
	1st half	2d half	1st quarter
New contracts:			
Average price	125.9	128.9	154.8
Percent of volumes sold between—			
0 and 50 cents	1.0	1.2	.2
51 cents and $1	23.4	20.6	6.3
$1.01 and $1.50	45.0	41.9	36.4
$1.51 and $2.00	29.2	31.8	56.9
$2.01 and $2.50	1.4	4.5	.2
Renegotiated contracts:			
Average price	141.6	146.0	178.0
Percent of volume sold between—			
0 and 50 cents	4.4	3.9	.7
51 cents and $1	17.1	12.2	11.3
$1.01 and $1.50	31.6	32.4	7.5
$1.51 and $2.00	44.8	46.9	47.6
$2.01 and $2.50	-2.1	4.6	32.9

Source: Intrastate natural gas prices, FPC form 45, news release Nos. 21987, 22237, 22398.

B. COMMODITY VALUE

The commodity value of natural gas also plays a role in our price determination. Our mandate is to achieve an adequate supply of natural gas at the lowest possible price. So long as gas is priced below its commodity value (as set by the price of other energy alternatives, including conservation), there will be excess demand. This simply means that at that price, consumers will demand more gas than producers will supply.

Regardless of the origin of today's energy pricing structure, interstate gas clearly is priced well below its commodity value in relation to that structure, and substantial excess demand is therefore present. This excess demand is reflected in the curtailments of firm delivery contracts by many pipelines and the limits on new customers in most parts of the country. Gas production peaked in 1973 and has fallen steadily since then.

Of course it would be improper to increase the ceiling price of natural gas if we believed that both supply and demand were totally inelastic. But we do not believe that they are. Not only have many empirical studies indicated substantial supply and demand elasticities, but supply conditions are also right. There are millions of acres of OCS leases that have yet to be explored and many onshore fields where it is not profitable to produce gas at historic prices but will be so at the price we set herein. There is an ample supply of drilling equipment available both on and offshore.

We are mindful that if we were to set the price herein solely on the basis of its

[197] *Id.*, at 426.
[198] *Id.*, at 436.
[199] *Id.*, at 444.
[200] 46 F.P.C. 86 (1971).
[201] 46 F.P.C. at 102.
[202] *Placid Oil Co.* v. *FPC*, 483 F.2d 880, 891 (1973) *affirmed sub nom., Mobil Oil Corp.* v. *FPC*, ____ U.S. ____ (June 10, 1974).
[203] *Southern Louisiana Area Rate Cases* v *F.P.C., supra.*
[204] See Opinion No. 699, -- F.P.C. --, slip opinion at 16.
[205] The term "commodity value" referred to the value of natural gas calculated by determining the price and availability of substitute fuels to the consumer, and subtracting a reasonable allowance for transportation and distribution to arrive at a field price for natural gas. See Appendix B of IPR Response in Docket No. R-389-B.
[206] *Shell Oil Co.* v. *FPC*, -- F. 2d -- (USCA 5th Cir. 1975), *cert. denied*, -- U.S. --, June, 1976.

commodity value, the excess demand for natural gas would not be reduced to zero because of rolled-in pricing by pipelines and the existence of a large base of pre-1/1/73 flowing gas at low prices. Pricing near commodity value over time will, however, lead to a gradual reduction in the excess demand as post 12/31/72 gas becomes increasingly dominant in total supply.

Thus, we find it useful to examine the commodity value of natural gas in today's energy markets.

Exhibits 28 and 29 detail some of the actual prices of competitive fuels within the U.S. economy. To compare these prices, we have taken observed prices of oil in various sectors of the country, and estimated the well-head price for natural gas which would be competitive at the average market. This estimation takes account of the cost of transporting gas from well to the average market, and of the historic energy relationship of gas and oil, with gas selling at about 85% of the Btu-equivalent price of oil.[208]

Exhibit 28 reports prices paid by electric utilities for residual (No. 6) fuel oil over the twelve months ended January 1976, for the major oil-consuming sections of the country. Exhibit 26 uses the most recent spot price data from the Oil and Gas Journal. When the regional prices prices are weighted by each region's gas consumption, we get the following results:

	1,000 ft³ equivalent
Contract No. 6 oil to utilities	$1.43
Spot market No. 6 oil to utilities	1.28
Recent spot No. 2 distillate	1.57
Recent spot No. 6 residual	1.31

We also note that the FEA's $11.40 per barrel upper tier price for oil at the wellhead in early 1976 translates to a gas wellhead value of $1.67 per Mcf at 85% Btu-parity. This is well above the $1.42 price of this decision, since both prices include comparable escalation factors.

A further comparison with liquified natural gas (LNG) and synthetic natural gas (SNG) equivalent values requires attention. A recent report [209] noted that "The delivered cost to the pipeline of liquified natural gas to planned projects will be anywhere from 86.6¢ per million Btu (MMBtu) to $3.34." These equate to equivalent rates of 86.6¢ per Mcf and $3.24 per Mcf on a 1,000 Btu basis. The price of high-Btu SNG is uncertain, but unlikely to be lower than these LNG prices.

[208] This relationship was also used by the Canadian National Energy Board in their recent gas pricing decision. In that decision, the export price for natural gas to the United States was raised from the current $1.60 per Mcf to $1.80 per Mcf, effective September 10, 1976, and to $1.94 per Mcf, effective January 1, 1977. Statement of The Honorable Alastair Gillespie, Minister Of Energy, Mines and Resources On Export Gas Pricing, June 10, 1976.

[209] Oil & Gas Journal, V. 74, No. 28 (July 12, 1976), p. 20. The report makes note of plans to purchase gas f.o.b. Algeria and Indonesia at $1.25 to $1.50 per MMBtu (or per Mcf), with additional shipping and terminal costs of $1.30 to $1.60 per MMbtu (or per Mcf). The only LNG cited at less than $1.42 per MMBtu is that contracted from Algeria in 1972 at a base price of 30.5 cents.

EXHIBIT 28.—*Utility residual (No. 6) prices, monthly average (February 1975 to January 1976)*

Geographic area	Prices paid (cents per 10⁶ Btu)		Distance from wellhead (miles)	Wellhead equivalent price (cents per 1,000 ft³) [1]	
	Contract	Spot		Contract	Spot
New England	156	179	1,500	122	107
Mid-Atlantic	166	187	1,300	129	120
South-Atlantic	183	190	1,000	126	125
Pacific	253	220	1,500	170	142
Average				137	128

[1] Wellhead equivalent is based upon 85 pct parity at city-gate, with 3¢/1,000 ft³ 100 mi transportation and 1,000,000 Btu's per 1,000 ft³.

Source: Reports on fuel cost, quality, Federal Power Commission.

EXHIBIT 29.—*Spot prices, June 1976*

Location-type	Average price [1]	Average price, cents per 10⁶ Btu	Distance from wellhead (miles)	Wellhead equivalent price (cents per 1,000 ft³)
Mid-Continent:				
Distillate No. 2	28.57¢/gal	208	[illegible]	153
No. 6	$10.75/bbl	171		121
Chicago:				
Distillate No. 2	30.75¢/gal	222	1,000	159
No. 6	$12.10/bbl	192		138
New York Harbor:				
Distillate No. 2	32.02¢/gal	[illegible]	1,300	157
No. 6	$12.92/bbl	205		135
Average				143

[1] Source: "Oil and Gas Journal," June 7, 1976.

C. ECONOMIC IMPACT

Sections 4(a) and 5(a) of the Natural Gas Act require that the rate prescribed herein be just and reasonable. The Courts have set forth several guiding principles for judging the economic impact of natural gas rate regulation. In the *Hope* case, the Supreme Court declared that the purpose of the Natural Gas Act was "to protect consumers against exploitation at the hands of natural gas companies".[210] The Courts have also recognized that consumer protection embraces adequacy of supply as well as the lowest reasonable price.[211] We do not view these as competing objectives, but rather as a dual requirement for a "just and reasonable" rate. The cost to consumers is just as real whether it takes the form of inadequate service or an excessive price.

We have determined that a national base rate of $1.42 per Mcf, plus annual escalations of 4 cents per Mcf, is necessary to induce producers to make long-term investments to replace the volumes being consumed and to find additional reserves for the anticipated market growth. Such investments will not be made unless producers are offered the prospect of a reasonable rate of return after all costs and taxes are paid. While we know of no data that will enable us to estimate the amount of new reserves this price will elicit, we are convinced that a cost-based rate, inclusive of a competitive market rate of return and an adequate tax allowance, is the appropriate supply-eliciting price in this proceeding. Not only will such a ceiling price safeguard consumers against "exploitation", since it is demonstrably below the maximum prices that could be exacted for new interstate gas in today's sellers' market, but it will also provide the economic incentive for producers to risk their capital in drilling for new reserves in areas where the prospective discoveries were not economically attractive at the pre-existing ceiling price.

The new national rate will affect gas supplies available both to current gas users and non-users, as well as reducing general demand for gas. Based on our understanding of current gas supply prospects, we would hesitate to predict that higher prices will reverse the downtrend of gas production that has been experienced during the past few years—we note, for example, that marketed production in the first quarter of 1976 was 2.8 percent lower than a year earlier and that domestic sales to interstate pipelines were 4.3 percent lower.[212] Nevertheless, we are confident that the supply situation will deteriorate more rapidly, especially in the interstate market, if prices are not allowed to increase. The consequence of such deterioration will be the further shift of energy use to higher-priced alternate fuels, notably oil imported from the Middle East. The increased availability of incremental gas supplies at the national rate was have prescribed herein will be a less expensive alternative for the Nation's consumers.

It should also be noted that natural gas has been supplying almost 50 percent of the energy consumed by the industrial

[210] *FPC* v. *Hope Natural Gas Co.*, 320 U.S. 591, at 610 (1944).

[211] *Mobil Oil Corp.* v. *F.P.C.*, 417 U.S. 283 (1974).

[212] Source: U.S. Bureau of Mines and FPC Form 11.

sector of the economy.[213] The availability of increased gas supplies to the industrial sector, particularly to those industries where gas cannot be efficiently replaced with other fuels, will contribute to increased productivity and a growing national economy.

These direct and indirect benefits to all Americans cannot be achieved at the current level of prices for natural gas. The higher prices authorized by this order will impose certain higher costs on some existing gas users as a necessary concomitant of creating the overall benefits.

It would be possible to make assumptions as to the amount of gas now flowing whose price would increase and the amount of new gas that would be called forth by the new price. These numbers could then be used to calculate a price impact for different usage levels.[214] But such an exercise would be simplistic and invalid. It would be assuming that the usage patterns of present consumers will be unaffected by price, and it would ignore the savings from reduction in the use of alternate fuels. While the magnitude of such impacts may be disputed, their direction is quite clear.

Appendix D presents a staff study which attempts to quantify all of the impacts of higher prices, and concludes that there will be a net benefit to all Americans, primarily because of the lessening of dependence on foreign oil. While we do not depend on the exact validity of the numbers in that study, we do maintain that it demonstrates the offseting costs and cost-savings of a proper cost-based national rate. Whether the true result is a net benefit of the size argued in the Appendix, or a smaller benefit or even a small net cost, cannot be known until the event. But the reasoning of that Appendix correctly demonstrates that higher costs to those who happen to have access to an assured supply of natural gas will be approximately offset by the benefits to those who will now be able to get gas for high-value economic activity. Conservation considerations have been taken into account as required by the Energy Policy and Conservation Act.[215]

[213] Data from U.S. Bureau of Mines, as published in 1974 Gas Facts, American Gas Association, page 58.

[214] *E.g.*, assuming 0.85 Tcf per year of 1973–74 vintage gas sells at a price of 107.1¢ per Mcf (including gathering allowance and state taxes) rather than the current 55.6¢ per Mcf, and that all gas qualifying under this Opinion (assumed to amount to .90 Tcf per year initially and increasing steadily to 1.35 Tcf by the end of the forthcoming year) sells at 150.1¢ per Mcf to 153.1¢ per Mcf over the year rather than 55.6¢ per Mcf, we could estimate the price of gas will increase 13¢ per Mcf in the forthcoming year, and thus estimate the average residential gas user, consuming 120 Mcf per year, will pay about $15.60 more per year. But for the reasons indicated in this section, such an analysis would be misleading and inaccurate if extended to the long run.

[215] Public Law 94–163, 89 Stat. 871, 939–40, 42 U.S.C. 6362.

D. OTHER ECONOMIC FACTORS

1. Supply/Demand

The effect of the higher price for new gas established herein will be to increase supply and reduce demand for natural gas relative to what they would have been in the absence of such an increase. The extent of such effects cannot be predicted with a sufficient degree of accuracy to warrant reporting herein. Yet outlining the nature of the impact is useful.

(a) Insofar as gas supply is increased, it will substitute for the more expensive energy alternatives. With imported oil currently selling at a Btu equivalent gas price of nearly $2.25 per Mcf, the substitution of less expensive gas for more expensive oil will have a significant effect on the overall inflationary impact of this price.

(b) It has been estimated [216] that the national gain from all cost-effective conservation measures would be about $9 billion in 1980. Present natural gas consumers account for a disproportionate share of the costs of energy waste, in large measure because their gas has been so cheap. We must recognize the significant degree of conservation which is possible in each sector if consumers take those efficiency-improving steps that did not pay for themselves at old prices, but do pay in saving the higher-priced gas (even at the rolled-in price.)

2. Outer Continental Shelf (OCS) Lease Bonuses

There is, of course, some uncertainty regarding OCS drilling costs and productivities. If higher offshore productivities more than offset higher drilling costs, producers will have an opportunity to earn higher profits. Some or all of these profits can be captured by the Federal government through competitive bidding for leases, with the extent of this offset determined by the degree of competition in the bidding. Thus, insofar as OCS gas might be overpriced, this method of sharing the national benefits of OCS gas appears more equitable than a simple distribution, through lower prices, to consumers who happen to have access to gas supplies.

3. Tax Revenues

Given our decision to employ the full corporate tax treatment for producers, the effect of this decision on Treasury receipts should be significant. Exhibit 30 contains a reconciliation between the cost and price determination components of Opinion No. 699–H and this opinion. The net effect of the change on taxes is estimated at 43.7¢ per Mcf using a productivity factor of 300 Mcf per foot. If a total of 2.1 Tcf of gas produced during the next year is subject to the price set herein, producers will pay $918 million in federal income taxes. Insofar as this reduces the need to tax consumers to support governmental activities, the impact of the higher price set herein is mitigated. Insofar as the gas from wells drilled during the previous biennium cost less than the current cost estimates employed herein, further tax liabilities will be incurred by producers. It should also be noted in Exhibit 30 that with the increase in price due to the inclusion of taxes, royalty payments would increase $175 million dollars [2.1 Tcf x (.2579—.1746)], with Federal domain royalties going to the Treasury and with an unknown fraction of the remaining amount also going to taxes.

To the extent our decision stimulates more drilling activity, immediate producer cost write-offs will allow many of these tax payments to be deferred, but the incremental tax liability will remain. Indeed, the rate calculations recognize the time value of this deferral to producers.

[216] "Economic Benefits of Energy Conservation", Proceedings of U. of Miami/ERDA Forum on Energy Conservation, December 1975.

EXHIBIT 30.—*669–H reconciliation*

	Original 699–H	699–H with 1975 cost data	699–H with 1975 cost and 1976 tax treatment
Basic data:			
Productivity (thousands of cubic feet)	[illegible]	[illegible]	300
Drilling costs per foot	29.83	38.53	[illegible]
Dry hole factor	1.00	.80	.80
Productive life (years)	[illegible]	15	15
Cost components (cents per thousand cubic feet):			
Other exploratory	[illegible]	4.73	4.73
Exploratory O/H	.83	1.71	1.71
Lease acquisition	4.28	14.13	14.13
Dry hole	3.72	8.12	8.12
Successful well	6.15	12.84	12.84
Recompletion	.20	.50	.50
Other production factor	1.39	3.44	3.44
	19.36	45.47	45.47
Cost allocated factor (percent)	NA	[illegible]	91
Allocation cost (cents per thousand cubic feet)			41.38
Working capital (cents per thousand cubic feet)	.46	[illegible]	1.33
Level Price (cents per thousand cubic feet)	53.47	109.10	161.16
Royalty	8.55	17.46	25.79
Total operating expense	[illegible]	2.91	2.91
Liquid credit	(3.89)	0	0
Taxes (net)	0	0	43.72
Return of investment	[illegible]	41.38	41.38
Return on investment (includes working capital)	26.15	[illegible]	[illegible]

VI. Rate Adjustments

A. Deeper Drilling and Deeper Offshore Water Depths

In the order of December 4, 1974, instituting this national rate proceeding, the Commission specifically requested the participants to address the issue of whether an increased allowance for deeper drilling and deeper water depths should be incorporated in the national rate structure. Opinion No. 699 provided no such allowance because the Commission therein determined that there was not a sufficient data base to establish a nationwide allowance. The Commission anticipated the compilation of a sufficient data basis in this biennial review to enable the Commission to determine the appropriate allowances for drilling efforts in deeper water and to greater depths. Four parties here addressed the costs associated with these extraordinary drilling activities.

The GHK Company and GasAndarko, Ltd. comments recommended a rate of return of at least 33% for wells drilled below a depth of 15,000 feet in lieu of the 15% rate of return adopted in Opinion No. 699–H. The recommendation was based upon greater capital risks, a 13% greater risk due to a lower average success ratio, a 51.6% greater risk for unanticipated drilling and completion problems, and an additional increment of 1.2 percentage points for the time value of money during longer drilling periods. GHK also stressed the problems of obtaining capital for deep drilling ventures.[217]

UDC submitted a study prepared by Dr. Root that estimated the initial recoverable reserves by size of field in the Deep Permian Basin formations in excess of 15,000 feet.[218] The study indicated that four large fields representing 9.3% of the total number, contained 63.7% of the total gas reserves discovered to date. Twenty-six intermediate fields, accounting for 60.5% of the total fields, contained 36.2% of the total reserves. Thirteen small fields contained only 0.1% of the total reserves.

UDC's evidence, although limited to deep drilling in the Permian Basin, estimates the well costs and the gas reserves found for certain fields at depths of 15,000 feet and greater. This evidence suggests a productivity for the deep wells of over 1100 Mcf per foot. If the large fields of over 400 Bcf are excluded, the productivity drops to about 845 Mcf per foot.

UDC estimated that the cost of drilling a deep gas well in the Permian Basin in 1974 was approximately $100 per foot. For the U.S., excluding Alaska, Joint Association Survey (JAS) drilling data for 1974 indicates a cost of $96 per foot for gas wells drilled below 15,000 feet. Assuming that the cost inflation for deep wells is comparable to that for all wells, the estimated cost of deep wells for the year 1975 would be $110 to $115.

Applying the productivity factors to the assumed cost of $115 per foot yields estimated successful well costs of about 10 cents per Mcf at 1100 productivity and 13.5 cents for 845 productivity derived from the medium and smaller fields. Thus, it appears that the average successful well cost for the deep Permian Basin is not greatly different from the average costs for the nation. Dry-hole risk and expense appears to be somewhat higher for the deep wells than for average wells,[219] but again the higher productivity would tend to offset the increase.

The evidence of GHK and Anadarko, Inc. demonstrates that the technical difficulties and substantial capital related to deep drilling entail more risk than average drilling. However, this evidence offers no indication of the rewards associated with deep drilling in terms of the amount of gas reserves found or the deliverability of the deep wells.

We once again do not have sufficient evidence to establish the extent to which costs of the average deep well may exceed the national average costs. Because of the nature of ultradeep drilling, there is not a large volume of nationwide cost and productivity available for such drilling activity.[220] Productivity, of course, is a key element and may not be as great for the average deep well as the data from Permian would suggest. Until such time, however, as we are presented with a broader sample of productivity data for deep wells, we have only the Permian data upon which to rely. That data does not adequately support nor enable quantification of a rate increment for the deep wells.

Two parties addressed the cost of drilling in ultra-deep water.

Initial comments were filed by Mr. Geer on behalf of IPR.[221] Mr. Geer compared the cost of producing nonassociated gas at water depths of 100 feet, 300 feet, 600 feet and 1,000 feet and estimated that Gulf of Mexico wells at water depths of 300 feet, 600 feet and 1,000 feet would cost 15%, 44% and 124% more, respectively, than a well at a water depth of 100 feet. Similar cost projections were made for the South Atlantic, North Atlantic, South Pacific and North Pacific offshore regions which reflected even higher costs at successive water depths.

Sun Oil Company (Sun) recommended an allowance for deep water drilling indicating that costs in deep waters are much greater than similar costs in shallow waters. In both instances, only expenditures were considered with the underlying assumption that productivity is the same in both deep and shallow waters.

Sun recommends that the deep water allowance be 1.5 times the nationwide rate. The evidence amply demonstrates that the cost of equipping the exploration and development effort in the ultradeep water is substantially in excess of costs in the more shallow water or on shore. Further, there is no sound geological reason to anticipate productivity to differ vastly relative to water depth. Nevertheless, while a simple multiplier would be appealing, there is not a sufficient evidentiary base for determining the multiplying factor.

The JAS report does not categorize offshore well costs by water depths, and the AGA does not report offshore reserves by depth below the ocean floor or by the overlying water depths. The absence of this information in the record makes the computation of a deep water drilling increment impossible in this proceeding.

Nevertheless, should adequate data become available, we would consider the initiation of the proceedings required to determine the appropriate allowances for drilling efforts to depths greater than 15,000 feet and drilling efforts in ultradeep water.

B. Btu Adjustment

In Opinion No. 699, the Commission provided an adjustment for Btu content allowing both upward and downward adjustments in the rate from a base of 1,000 Btu per cubic foot. The same adjustment will be provided in this proceeding.[222] This is the basis which was utilized in the prior rate proceedings.

For natural gas containing more than 1,000 Btu's per cubic foot, at 60° F. and 14.73 psia, upward adjustments shall be made on a proportional basis from a base of 1,000 Btu's per cubic foot; and for natural gas containing less than 1,000 Btu's per cubic foot, at 60° F. and 14.73 psia, downward adjustments shall be made on a proportional basis from a base of 1,000 Btu's per cubic foot. This adjustment shall be made after the base rate prescribed herein is adjusted for all state or Federal production, severance or similar taxes.

C. Tax Adjustments

The rate prescribed herein will be adjusted upward for all state or Federal production, severance, or similar taxes, effective the date deliveries are commenced, and shall be adjusted upward by 100% of any increase in such taxes subsequent to the date deliveries were commenced, and shall be adjusted downward by 100% of any decrease in such taxes subsequent to the date deliveries were commenced.

D. Pipeline PGA Filings

We have determined that jurisdictional pipelines having effective Purchased

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[217] Comments of GHK Company and GasAnadarko, Ltd., May 30, 1975.

[218] UDC Comments, May 14, 1975, Statement 5, Appendix A.

[219] See Comments of GHK Co., and GasAnadarko, Ltd., May 30, 1975, Exhibit V.

[220] The 1974 JAS report noted only 77 oil wells, 152 gas wells and 170 dry holes drilled to depths of 15,000 feet or greater. Oil wells and dry holes decreased significantly and gas wells decreased slightly from 1972 levels. The superdeep wells in 1974 accounted for less than 1.3% of all wells drilled in 1974.

[221] IPR Comments, May 30, 1975, Appendix E.

[222] Texaco, Inc., 33 F.P.C. 1228 (1965).

Gas Adjustment Clauses on file with the Commission should be permitted to make a one-time special purchased gas adjustment (PGA) filing to track the increased rates prescribed in this opinion. This reflects the same treatment afforded pipelines in Opinion Nos. 699–H and 749–A.

Accordingly, we shall waive the requirements of Section 154.38(d)(4)(iv) to permit the filing of this special PGA increase on or before September 27, 1976, to track all increases in purchased gas cost attributable to the rate prescribed herein which have been filed by natural gas producers under Section 2.56(j) on or before August 26, 1976. We shall permit an effective date of October 27, 1976. We recognize that requiring pipeline companies to file 30 days after the filing date for independent producers and requiring adherence to the 30-day notice requirements will delay recovery by the pipelines of the increased purchased gas cost. Therefore, we will provide for a surcharge to be added to the September 27, 1976, adjustment to enable the pipelines to recover the costs incurred prior to the adjustment in rates. No other increases in purchased gas cost shall be included in such filing. If a pipeline does not make this special PGA filing on or before September 27, 1976, such pipeline will be permitted to track the rates prescribed in this opinion solely through its regular semiannual PGA filings.

E. REFUNDS AND RATE REDUCTIONS

We have determined that natural gas producers who elect to discharge their existing refund obligations under prior area rate opinions by dedicating new supplies of natural gas to the interstate market covered by the opinion will be required to price such natural gas at the applicable area rate.[223] Those natural gas producers making small producer sales who elect to discharge their existing refund obligations by such new dedications will be required to price such natural gas at the rates established in area rate proceedings as modified by Opinion No. 742.[224] Producers who desire to obtain the contingent escalations for flowing gas as provided in Opinion Nos. 595, 598, 607, and 662 will be required to dedicate those new natural gas supplies which they seek to have applied toward triggering the flowing gas escalations at the rates provided in those opinions.

This treatment is consistent with that afforded producers in Opinion Nos. 699[225] and 749[226] for the same reasons as specified therein. Where a producer has commenced a sale of natural gas in interstate commerce and the volumes of gas from that sale are being credited toward the producer's refund obligation or applied to triggering the contingent escalations in the aforementioned area rate opinions,[227] the producer will not be allowed to receive both the price prescribed herein and continue to receive the refund credit or contingent escalation credit. The producer must make a decision as to whether it is more beneficial to receive the higher rate prescribed by this opinion and waive the refund credits and contingent escalations or to sell the gas at the applicable area rate or small producer rate and retain the refund credits and contingent escalations.

To help insure that producers do not gain both the higher rate under this opinion and the refund write-off or contingent escalation of prior orders, we shall require a written waiver of the contingent escalations and refund credits with respect to gas which is dedicated under the provisions of this opinion. That waiver shall state whether such gas has previously been sold in interstate commerce in discharge of refund obligations or toward the triggering of contingent escalations, the date the subject wells were commenced, and whether the gas was previously sold in interstate commerce under 18 C.F.R. §§ 2.68, 2.70, 154.22, or 154.29.

F. SPECIAL RELIEF

In Opinion No. 699, the Commission provided for special relief when the producer could demonstrate that out-of-pocket expenses incurred in the operation of a particular well were greater than revenues from the sale of the subject gas.[228] The Commission, therein, also permitted the producer to seek special relief when continued production became uneconomical or when Federal income tax liability required such relief. This same treatment was afforded producers in the previous area rate opinions.[229]

Similarly, in Opinion No. 749, we required the submission of a petition for special relief if the producer sought to charge a rate in excess of the national rate for "flowing gas" prescribed therein.[230]

Among the comments filed in this proceeding, Phillips Petroleum Company, in a supplemental response to that of the Producer Group, argues that the special relief approach utilized in Opinion No. 699 was sumbersome and time consuming. Phillips asserts that although the Commission provided procedures for special relief to cover the installation of compression equipment, relief was often too late to be effective. As an alternative, Phillips suggests the inclusion of an additive allowance where a seller performs compression and the seller and buyer jointly certify the need for such compression.[231]

From the evidence before us, it is impracticable to enumerate all of the circumstances which would form an adequate basis for granting special relief. It would be even more difficult to quantify an additive allowance which would be generally applicable to all compression expenditures or any other circumstance warranting special relief. For these reasons, we reject the suggestion of Phillips to isolate compression expenditures as a separate element in the rate structure. Accordingly, we have determined that it should be incumbent upon the producer seeking special relief to specify the circumstances that warrant such relief and to prove by his books and records that special relief is justified.

G. GATHERING ALLOWANCE

The Commission has provided for gathering allowances in both of the previous nationwide rate opinions (Opinion No. 699–H and Opinion No. 749). In those opinions we determined that a gathering allowance should be added to the base rate on an area basis. We find no reason to depart from the procedures set forth in our prior opinions.

Producer Witness Click, on behalf of IPR, presented certain evidence with respect to recently installed gathering systems and recommends a 6¢ per Mcf allowance be added to the national rate where substantial gathering takes place.[232] The data presented purports to show the costs of 13 gathering systems which have been installed since 1970. The data is presented basically on a state by state basis and as such prevents us from identifying precisely where the systems are located. Additionally, no distinction can be made as to whether the lines are carrying intrastate or interstate gas. For example, the second highest gathering cost per Mcf shown in Exhibit RRC–1 of the IPR Comments is in California where all of the gas remains in intrastate commerce.

Accordingly, without specific details on the lines as to capacity, there is no way to determine a time cost per Mcf. From the evidence presented we find no justification for changing from the previous allowances recommended in Opinion No. 699–H.[233]

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[223] *Southern Louisiana Area Rate Proceeding*, Docket No. AR69–1, et al., Opinion No. 598, 46 F.P.C. 86, 141, 147–148 (1971); *Texas Gulf Coast Area Rate Proceeding*, Docket No. AR64–2, et al., Opinion No. 595, 45 F.P.C. 674, 709–710, 721 (1971); *Other Southwest Area Rate Proceeding*, Docket Nos. AR67–1, et al., Opinion No. 607–A, 47 F.P.C. 99, 100, 102 (1972); *Area Rate Proceeding (Permian Basin Area II)*, Docket No. AR70–1 (Phase I), Opinion No. 688, ____ F.P.C. ____ (August 7, 1973).

[224] *Exemption Of Small Producers From Regulations*, 45 F.P.C. 454 (1971), as amended 45 F.P.C. 548 (1971), reh. denied, 46 F.P.C. 47 (1971), rev'd sub nom. *Texaco Inc., et al.* v. *F.P.C.*, 474 F.2d 416 (D.C. Cir. 1972), vacated and remanded, 417 U.S. 380 (1974). *Small Producer Regulations*, Opinion No. 742, ____ F.P.C. ____ (August 28, 1975).

[225] See Opinion No. 699, ____ FPC ____, slip opinion at 99–100.

[226] See Opinion No. 749, ____ FPC ____, slip opinion at 43.

[227] See n. 226, supra.

[228] See Opinion No. 699, ____ FPC ____, slip opinion at 105.

[229] E.g., see *Permian Basin Area Rate Cases*, 390 U.S. 747, 770–773.

[230] See Opinion No. 749, ____ FPC ____, slip opinion at 54.

[231] See Comments of Phillips Petroleum Co., June 2, 1975.

[232] IPR Comments, May 30, 1975, Appendix N.

[233] See § 2.56a(d), Ordering Paragraph, infra.

H. SMALL PRODUCERS

The Commission did not make small producers respondents to this proceeding since small producer rates are the subject of a separate proceeding. We are contemporaneously issuing an order upon rehearing of Opinion 742 which will govern small producer rates. Small producer rates will be governed by that opinion.

I. RATES FOR THE APPALACHIAN-ILLINOIS BASIN AREA

As we stated in Opinion No. 699–H, the IOGA proceeding [234] "* * * will develop information which may be useful in determining whether separate rates should be established for the Appalachian area in the future and the potential level of those separate rates. * * *" [235]

On March 19 and 22, 1976, respectively, the Commission issued orders approving settlements in Docket No. RI74–188 [236] and Docket No. RI75–21. The rates approved therein applied to both old and new gas produced by small producers in West Virginia meeting the criteria set forth in the Commission's orders issued April 10, 1975, in each docket.[237] The rate authorized in Docket No. RI74–188 was 62.85 cents per Mcf, effective March 19, 1976, for all gas flowing before January 1, 1973. The rates established in Docket No. RI75–21 were $1.00 per Mcf for gas from wells commencing jurisdictional sales during 1973, 1974, or 1975 and $1.158 per Mcf for wells commencing on or after January 1, 1976.

We find that the rate structure prescribed in this opinion is adequate for new gas from the Appalachian-Illinois Basin.

J. PIPELINE PRODUCTION

By Opinion No. 568,[238] the Commission determined that natural gas produced from leases acquired after October 7, 1969, by a pipeline or pipeline affiliate would be priced at the area rate applicable to gas of the vintage which corresponds to the date that the first well on the lease is completed.[239] Opinion No. 568 also continued the cost of service treatment for pipeline production from leases acquired prior to October 7, 1969.

Opinion No. 699–H amended the Commission's Regulations with respect to the vintaging of pipeline or pipeline affiliate production by providing that natural gas qualifying under Section 2.56a(a) of the Regulations would be entitled to the rate established in that opinion regardless of the date the lease was acquired or the first well was drilled, thereon.

We have determined that it is in the public interest to continue the policy adopted in Opinion No. 699–H. The rate prescribed herein applies to pipeline or pipeline affiliate production which qualifies under Section 2.56a(a)(1) as amended herein [240], regardless of the date on which the subject lease was acquired or the first well was drilled thereon.

VII. ENVIRONMENTAL IMPACT

Implementation of this decision will result in increased exploration and development activity. The extent of such increased activity is not known and is not susceptible of meaningful quantification. The location and extent of such activity will further depend upon the results of the initial exploratory activity and the size of the gas reserves ultimately discovered or not discovered. This Commission has no authority to compel private entities to explore for natural gas supplies for the interstate market; our jurisdiction merely extends to the regulation of the rates and service for natural gas that is sold in interstate commerce. Since we lack the power to compel exploration, we cannot compel these private entities to explore for new natural gas supplies in any given geographical area. As a result, it is impossible to determine in advance what environmental impact will occur as a result of increased exploration and development activity, or where within the continental United States such environmental impact will occur.

With respect to the development of new natural gas supplies from the offshore Federal domain, the Department of the Interior prepares final environmental impact statements before particular blocks are proposed to be leased. These statements are supplemented by the detailed environmental impact statements which this Commission requires before a major pipeline project to connect new offshore reserves is approved and construction allowed to commence.[241]

With respect to those new natural gas supplies discovered in the onshore (and offshore) domains of the several states, we have no authority to compel the sale of those natural gas supplies in interstate commerce unless these newly discovered supplies are located upon acreage which has been previously dedicated to an interstate pipeline company. This makes it impossible for the Commission to determine which exploration and development activities will be associated with a sale of new natural gas supplies in interstate commerce prior to the filing of an application for a certificate of public convenience and necessity authorizing the sale of natural gas to an interstate pipeline. We are, therefore, unable to predict which drilling activities will ultimately result in the sale and transportation of natural gas in interstate commerce subject to this Commission's jurisdiction.

Increasing the rates allowed for the sale of natural gas in interstate commerce may have some effect upon the ultimate end use of that gas in the various energy marketplaces. The ultimate end use of new natural gas supplies sold in interstate commerce is not readily definable, since the Commission does not know which interstate pipelines will actually purchase these new supplies for resale. To be sure, all interstate pipelines will purchase new natural gas supplies as they are able to contract for such supplies; however, the prices paid by the various individual pipelines and the various classes of customers to which the different interstate pipelines resell natural gas and the various proportions of the volumes which are consumed in particular end uses vary from pipeline to pipeline. These variations, plus the ability of the individual pipelines to acquire new supplies, add to the difficulties of predicting the environmental impact in the various energy consuming marketplaces.

The Commission anticipates that additional exploration and development activities will be undertaken as a result of this order and that additional supplies of natural gas will be dedicated to the interstate market. There exists no reliable methodology by which the location and extent of this exploration and development activity may be predicted, and we have no method for precisely predicting the volumes of new natural gas supplies that will be forthcoming at the rate established herein. *Placid Oil Company, et al.* v. *FPC*, 483 F. 2d 880, 900–902 (5th Cir. 1973), affirmed sub nom. *Mobil Oil Corp.* v. *FPC*, 42 U.S.L.W. 4842 (U.S. June 10, 1974).

We can conclude that there may be some adverse environmental impact as the result of increased exploration and development activity which is undertaken because of the decision in this proceeding. There may also be some adverse environmental impact as the result of pipeline projects undertaken as a result of the decision rendered in this proceeding. None of the potential adverse environmental impacts which may result from the increase in rates allowed by this decision is reasonably susceptible to any sort of quantification.

The present action will tend to increase gas supplies and to diminish the inefficient use of available gas. It will

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[234] *Independent Oil and Gas Association of West Virginia*, Docket No. RI75–21. This proceeding involved a petition for special relief from the national rate.

[235] Opinion No. 699–H, —— FPC ——, slip opinion at 65.

[236] *Independent Oil and Gas Association of West Virginia*, Docket No. RI74–188. This proceeding involved a petition under Section 5(a) of the Natural Gas Act.

[237] The criteria set forth in both RI74–188 and RI75–21 was identical.

[238] *Pipeline Production Area Rate Proceeding (Phase I)*, 42 F.P.C. 738, as amended, 42 F.P.C. 1089 (1972), affirmed, *City of Chicago* v. *F.P.C.* 147 U.S. App. D.C. 312, 358 F.2d 731 (D.C. Cir. 1971), cert. denied, 405 U.S. 1074 (1972). (Opinion No. 699–H).

[239] 42 F.P.C. 736 at 754, 18 C.F.R. § 2.66(a). (Opinion No. 699–H).

[240] See Ordering paragraph A, infra.

[241] 18 C.F.R. §§ 2.80, 2.81, *Implementation of the National Environmental Policy Act of 1969*, 44 F.P.C. 1531 (1970), *as amended*, 45 F.P.C. 563 (1971), as amended, 46 F.P.C. 1240 (1971), as amended, Order No. 415–C, 48 F.P.C. 1442 (1972), *reh. denied*, 49 F.P.C. 359 (1973); *Implementation of the National Environmental Policy Act of 1969*, Docket No. R–478, Order No. 485, 49 F.P.C. 1280 (1973). These requirements apply to both onshore and offshore projects.

substitute a small amount of clean-burning gas for a larger amount of dirtier fuels. We cannot predict the relationship between the location of fuel use and the air quality in those locations. Neither can we be sure that air-quality benefits outweigh the environmental costs of added gas production. But we can be confident that the aggregate end-use environmental impacts will be beneficial.

VIII. Conclusions

A. General conclusions

The just and reasonable national rate for post-January 1, 1975 gas supplies dedicated to the interstate market and the revised rate for qualifying 1973–1974 biennium gas supplies prescribed in this decision are founded on costs. In addition, the Commission has examined other relevant facts such as intrastate market prices, the "commodity value" of natural gas, supply and demand effects, and the cost of alternate fuels in evaluating the sufficiency of the cost-based rate for new supplies.

Each of the elements of the rate structures is interdependent upon all of the other elements and stands not by itself but as part of the whole.

In our opinion, the rates prescribed herein are at a level which will serve the public interest by increasing the supply of natural gas available to the interstate market and which will effect a more efficient utilization and allocation of the nation's natural gas resources in an intercompetitive fuel economy.

In summary, the total rate design herein found to be just and reasonable consists of the following integral elements:

1. A base rate of $1.42 per Mcf for post-January 1, 1975 gas (with quarterly escalations of 1.0 cent per Mcf) subject to Btu adjustment plus reimbursement for production, severance, or similar taxes, and gathering allowances (including the onshore delivery of offshore gas at the cost of the producer) for qualifying sales;

2. A base rate of $1.01 per Mcf for qualifying 1973–1974 biennium gas subject to Btu adjustment plus reimbursement for production, severance, or similar taxes, and gathering allowances (including the onshore delivery of offshore gas at the cost of the producer) for qualifying sales;

3. Allowance of the rate established in Opinion No. 699–H for sales formerly made pursuant to contracts which have expired by their own terms where a qualifying renewal contract is submitted to the Commission for certification; and

4. Provisions for certain adjustments to the national rate.

We have "adopted a total rate structure to motivate private producers to fully develop [the nation's natural gas] resources" [342] while assuring the consumer an adequate supply of gas at a reasonable rate. This total rate structure represents a solution "capable of equitably reconciling the diverse and conflicting interests" [343] which are presented on the record of this proceeding. It is true that certain portions of this rate structure favor some producers or some consumers more than other members of those classes of persons. There is always "some discrimination aris[ing] from the mere fact of [national], rather than individual producer, regulation," [344] but such discrimination is permissible if the overall balance of the order is not unjust and unreasonable. We are of the opinion that the "overall balance" of the rate structure established herein is just and reasonable.

B. Additional comments

In reaching this decision the Commission has reviewed the judgments and conclusions as set forth in the dissenting opinion. The legal, factual and policy considerations which support the Commission's findings and conclusions are interspersed throughout the majority opinion and need not be restated. Having considered the dissenting opinion herein we are not able to agree that the record supports the judgments or conclusions therein reached nor do we conclude that legal or policy considerations warrant or permit such judgments and conclusions.

Additionally, we believe the dissenting opinion misconceives the nature of the holding of the majority opinion in several important respects. The Commission has here established a rate of $1.42/Mcf escalating at 1¢ per quarter for post-December 31, 1974 gas. The Commission has also established a rate of $1.01/Mcf for gas dedicated and wells drilled on or after January 1, 1973 and prior to January 1, 1975. The reference in the majority opinion to $1.63/Mcf is an arithmetic calculation.

In reference to productivity determination the Commission did not compute the calculation that the dissenting opinion sets out.

The dissent states that it is necessary to lag the reserves-added data one year behind the drilling footage data to compensate for AGA errors. There is simply no evidence in the record to support this new and heretofore undisclosed methodology. There is certainly no evidence that a one-year period reflects the "average effect" of the errors. In fact, the Staff Report on the 31-Lease Investigation indicated that the AGA figures reported fields as being discovered both earlier and later than the same fields as reported by producers.

Revisions are an important piece of information. They improve overall reserve estimates, and their exclusion should be carefully considered before being adopted. If adjustments are made to the annual reserve additions to exclude revisions from prior years, the assumption would have to be made that such reserve revisions apply only to years prior to the series used in deriving a productivity factor. In other words, such revisions would have to be applicable to pre-1967 reserve additions only, if a nine-year productivity average is employed. This is certainly a questionable assumption since a portion of these revisions would likely apply to reserve additions reported from 1967 to 1975.

We find no record support for the calculation and therefore we cannot share the view expressed in the dissenting opinion.

In regard to the discussion of non-cost factors, the dissent only chooses to recognize those which lead to a lower price. We have examined a set of intrastate prices and commodity values and do not embrace any particular component. We only use these factors to assure a just and reasonable rate.

The purpose of the advance payments program was to provide producers with additional capital in order to promote additional drilling activity. These advanced payments are not lost to the consumers but will be recouped by the pipelines with the receipt of new supplies of gas. In any event, the program is now terminated and does not belong in a prospective price determination that has the underlying purpose of eliciting new supplies of natural gas.

Finally, the economic impact, as discussed in the dissent, was not placed in the proper perspective. The additional annual costs to consumers for gas supplies under expiring contracts would remain the same under this opinion as under Opinion No. 699–H. The repricing of 1973–1974 biennium gas is also essential, if only to track the additional tax liability resulting from the repeal of percentage depletion.

We anticipate that, in any application for rehearing of the Commission's opinion and order, additional commentary may be appropriate in light of the arguments and positions which the majority and minority opinions may prompt. The Commission welcomes any such further opportunity.

The Commission finds. (1) The notice and opportunity to participate in this rulemaking proceeding with respect to the matters currently before this Commission through the submission in writing of data, views, comments, and suggestions in the manner described above are consistent and in accordance with the procedural requirements prescribed by 5 U.S.C. 553.

(2) Good cause exists that the revisions adopted herein become effective upon issuance of this order.

(3) The revisions adopted herein are in the public interest and are necessary and appropriate for the administration of the Natural Gas Act.

The Commission, acting pursuant to the provisions of the Natural Gas Act, as amended, particularly Sections 4, 5, 7, 8, 14, 15, and 16 thereof (52 Stat. 822, 823, 824, 825, 828, 829, 830 (1938); 56 Stat. 83, 84 (1942); 61 Stat. 459 (1947);

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[342] *Placid Oil Co.* v. *F.P.C.*, 483 F.2d 880, 891 (1973), affirmed sub. nom. *Mobil Oil Corp.* v. *F.P.C.*, —— U.S. ——, —— (June 10, 1974) (see slip opinion at 43).

[343] *Mobil Oil Corp.* v. *F.P.C.*, supra, slip opinion at 37.

[344] *Mobil Oil Corp.* v. *F.P.C.*, supra, (slip opinion at 43), citing *Permian Basin Area Rate Cases*, 390 U.S. 747, 767 (1968).

76 Stat. 72 (1962); 15 U.S.C. §§ 717c, 717d, 717f, 717g, 717m, 717n, 717o (1970) 0, orders:

(A) The Statements of General Policy and Interpretations of the Commission, Part 2 of Subchapter A of Chapter I of Title 18 of the Code of Federal Regulations, are hereby amended by substituting revised § 2.56a as follows:

§ 2.56a National Rates for Sales of Natural Gas from Wells Commenced on or after January 1, 1973, and New Dedications of Natural Gas to Interstate Commerce on or after January 1, 1973, and Certain Other Sales.

(a) *Base national rates.* Notwithstanding any other provisions of the General Rules of the Federal Power Commission, or the Regulations under the Natural Gas Act, sales of natural gas in interstate commerce with qualify under the provisions of this subsection (a) may be made at rates herein provided.

(1) Sales of natural gas in interstate commerce for resale may be made at a rate of $1.42 per Mcf (at 14.73 psia), exclusive of all State or Federal production, severance or similar taxes, and subject to the adjustments provided in this section, and the escalation provided in paragraph (a) (2) of this section, provided the sale is within one or more of the following classifications:

(i) The sale is made from a well or wells commenced on or after January 1, 1975;

(ii) The sale is made pursuant to a contract for the sale of natural gas in interstate commerce for gas not previously sold in interstate commerce prior to January 1, 1975, except pursuant to the provisions of 18 CFR 2.68, 2.70, 157.22, or 157.29 (including sales made pursuant to those sections as modified by Federal Power Commission Order No. 491, et al.), or 18 CFR 2.75(n), where the sale is initiated on or after January 1, 1975, provided that no certificate for the subject sale has been issued under the optional procedure (18 CFR 2.75);

(2) The price prescribed by paragraph (a) (1) of this section may be increased by an amount not to exceed 1 cent per Mcf per quarter commencing on October 1, 1976, and the first days of January, April, and July of every year, thereafter, for the term of the contract dedicating the subject gas for sale in interstate commerce pursuant to the terms of the sales contract until such time as the price prescribed in paragraph (1) of this section (a) (1) shall be redetermined according to the provisions of paragraph (n) of this section.

(3) Sales of natural gas in interstate commerce for resale may be made at a rate of $1.01 per Mcf (at 14.73 psia), exclusive of all State or Federal production, severance or similar taxes, and subject to the adjustments provided in this Section 2.56a, provided the sale is within one or more of the following classifications:

(i) The sale is made from a well or wells commenced on or after January 1, 1973 and on or before January 1, 1975;

(ii) The sale is made pursuant to a contract for the sale of natural gas in interstate commerce for gas not previously sold in interstate commerce prior to January 1, 1973, except pursuant to the provisions of 18 CFR 2.68, 2.70, 157.22, or 157.29 (including sales made pursuant to those sections as modified by Federal Power Commission Order No. 491, et al.), or 18 CFR 2.75(n), where the sale is initiated on or after January 1, 1973 and before January 1, 1975, provided that no certificate for the subject sale has been issued under the optional procedure (18 CFR 2.75).

(4) Sales of natural gas in interstate commerce for resale may be made at a rate of 52 cents per Mcf (at 14.73 psi), exclusive of all State or Federal production, severance or similar taxes, and subject to the adjustments provided in this section and the escalation provided in paragraph (a) (5) of this section, provided the sale is made pursuant to a contract executed prior to or subsequent to the expiration of the term of the prior contract where the sales were formerly made pursuant to permanent certificates of unlimited duration under such prior contracts which expired of their own terms on or after January 1, 1973, or pursuant to contracts executed on or after January 1, 1973, where the prior contract expired by its own terms prior to January 1, 1973.

(5) The price prescribed by paragraph (a) (4) of this section may be increased by an amount not to exceed 1.0 cents per Mcf per annum commencing on January 1, 1977, and the first day of every year thereafter for the term of the contract dedicating the subject gas for sale in interstate commerce pursuant to the terms of the sales contract until such time as the price prescribed in paragraph (4) of this subsection (a) shall be redetermined according to the provisions of paragraph (n) of this section.

(b) *Tax adjustments.* The applicable rate prescribed in subsection (a) shall be adjusted upward for all State or Federal production, severance, or similar taxes, effective the date deliveries are commenced, and shall be adjusted upward by 100 percent of any increase in such taxes subsequent to the date deliveries were commenced, and shall be adjusted downward by 100 percent of any decrease in such taxes subsequent to the date deliveries were commenced.

(c) *Quality adjustments.* For natural gas sold in interstate commerce for resale subject to the rate prescribed in subsection (a) of this section, quality standards and the resulting adjustments to the base national rate shall be made as follows:

(1) *Btu adjustment.*—For natural gas containing more than 1,000 Btu's per cubic foot, at 60°F and 14.73 psia, upward adjustments shall be made on a proportional basis from a base of 1,000 Btu's per cubic foot; and for natural gas containing less than 1,000 Btu's per cubic foot, at 60° F and 14.73 psia, downward adjustments shall be made on a proportional basis from a least of 1,000 Btu's per cubic foot.

This adjustment shall be made after the rate prescribed in paragraph (a) (1) of this section is adjusted for taxes pursuant to paragraph (b) of this section.

The Btu content of the natural gas used in computing this rate adjustment shall be the number of British thermal units (Btu) produced by the combustion, at constant pressure, of the amount of the gas which would occupy a volume of 1.0 cubic feet at a temperature of 60° F saturated with water vapor and under a pressure equivalent to that of 30.00 inches of mercury at 32° F and under standard gravitational force (980.665 centimeters per second squared) with air of the same temperature and pressure as the gas, when the products of combustion are cooled to the initial temperature of the gas and air and when the water formed by combustion is condensed to the liquid state.

(2) *Other quality adjustments.*—All quality standards and the resulting adjustments to the rate prescribed in paragraph (a) (1) of this section shall be made in accordance with the provisions of the particular gas sales contract except that all Btu adjustments shall be governed by paragraph (1) of this section.

(d) *Gathering allowances.* The base national rate prescribed in subsection (a) of this section, as adjusted for Btu content and applicable taxes, shall be adjusted for gathering activities as follows:

(1) *Appalachian-Illinois Basin areas.*—The gathering allowance shall be 1.0 cents per Mcf for all sales of natural gas made from wells located in the Appalachian-Illinois Basin Areas.

(2) *Hugoton-Anadarko area.* — The gathering allowance shall be the amounts prescribed below where delivery of the gas is made after substantial off-lease gathering by the producer, whether at a plant tailgate or at a central point in the field.

(i) For gas produced in the Panhandle and Hugoton Fields, the allowance shall be 2.5 cents per Mcf.

(ii) For gas produced from fields or reservoirs other than the Panhandle or Hugoton Fields (the "Other Fields"), the allowance shall be 1.0 cents per Mcf.

(3) *Other Southwest area.*—The gathering allowance shall be the amounts prescribed below where the gas is delivered to the buyer at a central point in the field, the tailgate of a processing plant, a point on the buyer's pipeline, or an offshore platform on the buyer's pipeline.

(i) For gas produced in the Other Oklahoma Area, Texas Railroad District No. 9, and Northern Arkansas, the allowance shall be 1.5 cents per Mcf.

(ii) For gas produced in Texas Railroad District Nos. 5 and 6, Northern Louisiana, and Southern Arkansas, the allowance shall be 1.0 cents per Mcf.

(iii) For gas produced in Mississippi and Alabama, the allowance shall be 1.25 cents per Mcf.

(4) *Permian Basin area.*—For gas produced in the Permian Basin Area, the applicable gathering allowance shall be 1.5 cents per Mcf where delivery is made

after substantial off-lease gathering by the producer, whether at a plant tailgate or a central point in the field.

(5) *Rocky Mountain area.*—For gas produced in the Rocky Mountain Area, the applicable gathering allowance shall be 1.0 cents per Mcf where delivery is made to the buyer at a central point in the field, the tailgate of a processing plant, or a point on the buyer's pipeline.

(6) *Southern Louisiana area.*—For gas produced in the Southern Louisiana Area, the applicable gathering allowance shall be 0.5 cents per Mcf where the gas is delivered to the buyer at a central point in the field, the tailgate of a processing plant, a point on the buyer's pipeline, or an offshore platform on the buyer's pipeline.

(7) *Texas Gulf Coast area.*—For gas produced in the Texas Gulf Coast area, the applicable gathering allowance shall be 0.4 cents per Mcf where the gas is delivered to the buyer at a central point in the field, the tailgate of a processing plant, a point on the buyer's pipeline, or an offshore platform on the buyer's pipeline.

(e) *Delivery of offshore gas by the producer to an onshore area.* If natural gas produced offshore is delivered onshore, at the sole cost of producer, the uniform national rate shall be adjusted upward 1.0 cent per Mcf for such offshore gas.

(f) *Adjusted national rate.* The uniform national rate prescribed in paragraph (a) of this section, as adjusted pursuant to paragraphs (b), (c), (d), and (e), is the adjusted national rate, and such rate is applicable only to those jurisdictional sales described in paragraph (a)(2) of this section made within the United States including the adjacent offshore Federal domain but excluding Alaska and Hawaii. No seller may demand or receive any rate or charge in excess of the rate prescribed by paragraph (a), except for such adjustments described in paragraphs (b), (c), (d), and (e) of this section as may be applicable to the particular sale, unless the Commission after giving proper notice and providing an opportunity for the submission of comments shall modify the rate set forth in paragraph (a) of this section or grant a petition for special relief pursuant to paragraph (g) of this section.

(g) *Special relief.* Prior to the establishment of rates for the 1977–78 biennium pursuant to subsection (n), any seller seeking to charge a rate in excess of the adjusted national rate described in paragraph (f) of this section or requesting a change in either the base national rate prescribed in paragraph (a)(1) of this section or the adjusted national rate described in subsection (f) must file a petition seeking special relief for waiver or amendment of said subsections pursuant to § 1.7(b) of the Commission's Rules of Practice and Procedure (18 CFR 1.8(b)) fully justifying the relief sought in light of this order. Such seller may not file for any rate increase which results in a rate in excess of the adjusted national rate described in paragraph (f) of this section unless and until the Commission grants such petition for special relief.

(h) *Modification of area rate regulations.* To the extent that the Commission's Regulations Under the Natural Gas Act establishing area rates and conditions for sale of natural gas from the Southern Louisiana Area (18 CFR 154.105), Hugoton-Anadarko Area (18 CFR 154.106), Appalachian Basin Area (18 CFR 154.107), Illinois Basin Area (18 CFR 154.109), Other Southwest Area (18 CFR 154.109a), or Rocky Mountain Area (18 CFR 2.56(a), 154.109(b)), and the Permian Basin Area are inconsistent with the provisions set forth above the same are hereby modified to reflect the provisions set forth above. The provisions of the rate structures for these are modified only with respect to those sales which are certificated pursuant to the provisions of this section and in all other respects remain in full force and effect. Provisions pertaining to refund credits and contingent escalations are contained in paragraph (i) of this section.

(i) *Waiver of refund credits and contingent escalations.* Any natural gas certificated under the provisions of this section which a natural gas producer elects to have credited against his existing refund obligations in the Southern Louisiana, Texas Gulf Coast, Other Southwest Area, or the Permian Basin, or applied to the triggering volumes for the contingent escalations for those areas shall be priced at the rate prescribed in the applicable area rate opinion and not at the uniform national rate prescribed in this opinion. For purposes of this section, the applicable area rate opinions and Commission regulations are:

(a) *Area Rate Proceeding (Texas Gulf Coast Area)*, et al., Opinion No. 595, 45 F.P.C. 675 (1971); 18 CFR 154.109.

(b) *Area Rate Proceeding (Southern Louisiana Area)*, et al., Opinion No. 598, 46 F.P.C. 86 (1971); 18 CFR 154.195.

(c) *Area Rate Proceeding (Other Southwest Area)*, et al., Opinion No. 607–A, 47 F.P.C. 99 (1972); 18 CFR 154.109a.

(d) *Area Rate Proceeding (Permian Basin Area II)*, Docket No. AR70–1 (Phase I), Opinion No. 662, 50 F.P.C. 390 (1973).

With respect to gas of a class described in paragraph (a)(2) of this section which is currently being sold in interstate commerce in discharge of a refund obligation or was dedicated to interstate commerce in partial satisfaction of the triggering volumes for the contingent escalations in the described areas, such gas may be sold at the rate prescribed in paragraph (a) of this section only if the seller files a written waiver of the right with respect to such gas to discharge such refund obligations or to trigger the contingent escalations concurrently with the contractually authorized rate increase filing. The seller shall further state the date on which the subject wells were commenced, the present provisions under which the gas is being sold in interstate commerce, the dollar amount of existing refund obligations previously discharged by the sale of such gas, and the volumes (at 14.73 psia) applied to trigger the contingent escalations.

(j) *Effective date of rate filings and waivers of refund credits or contingent escalations.* Any contractually authorized increase rate filing made pursuant to the provisions of this order shall be effective as of July 27, 1976, if the filing is made on or before August 26, 1976, and as of the date of filing if the filing is made subsequent thereto.

A single filing may be made which covers the rates to become effective July 27, 1976, and the 1.0¢ periodic escalations to be effective October 1, 1976, January 1, 1977, and April 1, 1977, provided such filing clearly and distinctly shows the rates to be effective on these respective dates.

For those persons desiring to make separate filings to track the 1.0¢ periodic escalations to be effective October 1, 1976, January 1, 1977, and April 1, 1977, such filing shall be made on or before October 1, 1976, January 1, 1977, and March 31, 1977, respectively. Any filings made after October 1, 1976, will be subject to the thirty (30) day notice requirements.

(k) *Newly discovered reservoirs on previously committed acreage.* (1) In all areas, the rate for natural gas produced from a reservoir discovered on or after January 1, 1973, which is located upon acreage previously dedicated to interstate commerce under a contract dated prior to January 1, 1973, shall be determined by the date of discovery of such reservoir, in lieu of the contract date.

(2) Where a producer is entitled to an increase in the price of its gas based on the date of discovery of the reservoir from which gas-well gas sales (or residue gas derived therefrom) are being made, it may file a proposed price increase pursuant to section 4 of the Natural Gas Act, indicating to what gas the higher price will be applicable. With each filing the producer will include (i) copies of all documents filed with or issued by local or State regulatory agencies relating to the discovery of the reservoir from which the gas is produced, and (ii) a statement by the buyer of the gas that the gas qualifies for the price sought, or why the buyer believes it does not. The producer shall also furnish any additional material in its possession or available to it which the Commission may request in writing. Documents or other data previously filed with this Commission, whether by the producer or another, may be incorporated by reference in any filing hereunder. Similar information shall be filed in any pending section 4 proceeding to which it is relevant. The Commission will follow the determination made by the appropriate State agency in determining the date of discovery of a reservoir. In the event the State agency changes its classification of a reservoir, the Commission shall follow such change as of the date of the new classification. Whenever the reclassification of a reservoir affects the appli-

cable ceiling rate the producer and the buyer shall notify the Commission.

(l) *Pipeline production.* Natural gas production from leases owned by a pipeline or a pipeline affiliate may be priced at the rate prescribed in paragraph (a) of this section pursuant to the provisions of § 2.66(c) of this part (18 CFR 2.66 (c)).

(m) *Termination of rate ceiling.* The rate prescribed in paragraph (a)(1) of this section shall remain in effect until such time as rates are established pursuant to paragraph (n) of this section.

(n) *Review of National rate ceiling.* Prior to January 1, 1977, the Commission shall initiate such proceedings as shall be necessary to establish a just and reasonable rate to be effective from the date of establishment of rates by order of the Commission through December 31, 1978, for the sales described in paragraph (a)(2) of this section and for all wells commenced on or after January 1, 1977, and prior to January 1, 1978, all new dedications of natural gas to interstate commerce for the period January 1, 1975, through December 31, 1976.

(o) *Revision of § 2.56(h) (18 CFR 2.56 (h)).* By Opinion No. 699, the Commission promulgated a national rate structure as subsection (h) of Section 2.56 of its General Policy Statements and Interpretations (18 CFR 2.56(h)). By this Opinion No. 699–E, said § 2.56(h) is revised and designated as § 2.56a (18 CFR 2.56a). All certificates which may have been issued prior to this date pursuant to § 2.56(h) are hereby amended to reflect the change in codification of the national rate structure.

(p) *Effective date.* The effective date of this § 2.56a is July 27, 1976.

(B) Section 2.56(f) of the Commission's General Policy Statements and Interpretations, Part 2 of Subchapter A of Chapter I, Title 18, Code of Federal Regulations, is amended by adding a new paragraph (3) as follows:

§ 2.56 Area price levels for natural gas sales by independent producers.

* * * * * *

(f) * * *

(3) *Reservoirs discovered or dedicated to interstate commerce on or after January 1, 1973.*—The rate for new reservoirs discovered or dedicated to interstate commerce on or after January 1, 1973, shall be determined by § 2.56a(a) if the proposed sale comes within one of the classes enumerated in § 2.56a (a)(1).

* * * * * *

(C) Section 2.66 of the Commission's General Policy Statements and Interpretations, Part 2 of Subchapter A of Chapter I, Title 18 of the Code of Federal Regulations, is amended by adding a new paragraph (c) as follows:

§ 2.66 Pricing of new gas produced by pipelines and pipeline affiliates.

* * * * * *

(c) *National rate for pipeline or pipeline affiliate production.* Notwithstanding any other provision of this section 2.66, natural gas production from any lease owned by a pipeline company or a pipeline affiliate, regardless of the date of acquisition of the lease, shall be priced for ratemaking purposes at the rate prescribed in § 2.56a(a)(1) of this part if such production qualifies under the provisions of one or more of the enumerated classes of sales set forth in § 2.56a(a)(2) of this part. The provisions of § 2.56(f) (18 CFR 2.56(f)) shall apply to natural gas production which qualifies for the national rate treatment pursuant to this section.

(D) Notwithstanding the provisions of Section 154.38(d)(4)(iv) of the Regulations Under the Natural Gas Act [18 C.F.R. Section 154.38(d)(4)(iv)], any jurisdictional pipeline company having a purchased gas adjustment clause in effect as of the date of this order may file on or before September 27, 1976, a special rate increase to become effective October 27, 1976, to track the rates prescribed in Section 2.56(j). The special rate increase will be limited to those independent producer increases actually filed with the Commission on or before August 26, 1976. In addition, such pipeline company may file a surcharge to become effective on October 26, 1976, which will permit recovery of producer increases attributable to this opinion and actually collected prior to the adjustment date.

In the event any pipeline chooses to utilize the adjustment dates of its effective PGA clause in lieu of the above adjustment date, it will be permitted to do so. Should the special PGA filing not be submitted on or before September 27, 1976, the pipeline company will be required to use its regular PGA adjustment dates. After utilization of the special PGA adjustment permitted herein, any future adjustments to recover the effects at periodic escalations will be made under the regular operation of the individual company's effective PGA clause.

(E) Section 154.109b of the Commission's Regulations Under the Natural Gas Act, Part 154 of Subchapter E of Chapter I, Title 18, Code of Federal Regulations, is hereby amended by adding a new paragraph (d) as follows:

§ 154.109b Area rates—Rocky Mountain Area.

* * * * * *

(d) No rate or charge, made, demanded, or received under a rate schedule filed pursuant to this part for gas produced in the Rocky Mountain Area shall exceed 35.0 cents per Mcf measured at 14.73 psia and 60° F, subject to adjustment upward and downward Btu adjustment on a proportional basis from a base Btu content of 1,000 Btu's per cubic foot measured on a saturated basis, and exclusive of all State or Federal production, severance, or similar taxes, and sold under contracts dated on or after October 1, 1968, for wells commenced prior to January 1, 1973. This rate shall also be subject to a gathering allowance not to exceed 1.0 cents per Mcf where delivery is made to the buyer at a central point in the field, the tailgate of a processing plant, or a point on the buyer's pipeline.

(F) The Secretary shall cause prompt publication of this order be made in the Federal Register.

By the Commission.

Commissioner Smith, dissenting, filed as part of original document.

KENNETH F. PLUMB,
Secretary.

APPENDIX A.—*Allocation of dry hole footage to gas well footage,[1] year—1974*

Line No.		(1) Successful exploratory footage	(2) Percent of total	(3) Exploratory dry hole footage	(4) Allocated footage
1	Gas	7,665	61.3		[2] 23,091
2	Oil	4,833	38.7		[3] 14,578
3	Total	12,498	100.0	37,669	[4] 37,669
		Successful developmental footage	Percent of total	Developmental dry hole footage	Allocated footage
4	Gas	31,311	40.9		[5] 9,661
5	Oil	45,179	59.1		[6] 13,959
6	Total	76,490	100.0	23,620	[7] 23,620
		Total successful footage	Allocated dry hole footage	Dry hole factor	
7	Gas	38,975	32,752	[8] 0.84	
8	Oil	50,012	28,537	[9] 0.57	
9	Total	88,987	61,289		

[1] Footage in 1,000 ft, Alaskan data excluded.
[2] Col. (2), line 1 times col. (3), line 3.
[3] Col. (2), line 2 times col. (3), line 3.
[4] Line 1 plus 2.
[5] Col. (2), line 4 times col. (3), line 6.
[6] Col. (2), line 5 times col. (3), line 6.
[7] Line 4 plus 5.
[8] Col. (2), line 7 divided by col. (1), line 7.
[9] Col. (2), line 8 divided by col. (1), line 8.

Source: "API, Quarterly Review of Drilling Statistics for the United States."

Allocation of dry hole footage to gas well footage,[1] year—1975

Line No.		(1) Successful exploratory footage	(2) Percent of total	(3) Exploratory dry hole footage	(4) Allocated footage
1	Gas	7,980	58.6	23,451	[2] 23,091
2	Oil	5,640	41.4	16,567	[3] 14,578
3	Total	13,620	100.0	40,018	[4] 37,669
		Successful developmental footage	Percent of total	Developmental dry hole footage	Allocated footage
4	Gas	33,918	36.7	10,214	[5] 9,661
5	Oil	58,446	63.3	17,616	[6] 13,959
6	Total	92,364	100.0	27,830	[7] 23,620
		Total successful footage	Allocated dry hole footage	Dry hole factor	
7	Gas	41,898	33,665	[8] 0.80	
8	Oil	64,086	34,188	[9] 0.53	
9	Total	105,984	67,853		

[1] Footage in 1,000 feet, Alaskan data excluded.
[2] Col. (2), line 1 times col. (3), line 3.
[3] Col. (2), line 2 times col. (3), line 3.
[4] Line 1 plus 2).
[5] Col. (2), line 4 times col. (3), line 6.
[6] Col. (2), line 5 times col. (3), line 6.
[7] Line 4 plus 5.
[8] Col. (2), line 7 divided by col. (1), line 7.
[9] Col. (2), line 8 divided by col. (1), line 8.

Source: "API, Quarterly Review of Drilling Statistics for the United States.

APPENDIX B.—*Dry hole factors*

Year	(1) Dry hole	(2) Gas	(3) Oil	(4) Dry hole factor [1]
	New field wildcat footage (in thousands) [2]			
Exploratory:				
1967	24,023	1,469	2,245	6.47
1968	27,069	1,032	1,984	8.98
1969	31,425	1,669	2,258	8.04
1970	26,383	1,514	2,012	7.46
1971	23,328	1,553	1,519	7.59
1972	26,851	2,086	1,926	6.60
1973	25,507	2,957	1,786	5.39
1974	28,231	3,027	2,265	5.23
1975	30,748	3,955	2,815	4.98
	Other than new field wildcat footage (in thousands) [2]			
Developmental:				
1967	36,799	20,004	55,998	.4826
1968	37,485	19,683	56,681	.4912
1969	39,827	22,395	58,894	.4899
1970	32,482	21,376	54,377	.4290
1971	29,606	21,056	46,749	.4390
1972	32,350	24,656	46,487	.4547
1973	30,542	32,630	42,647	.4057
1974	33,056	35,948	47,747	.3880
1975	37,609	38,533	61,271	.3717

[1] $(4)=\frac{(1)}{(2)+(3)}$.

[2] Excludes Alaska.

Source: American Petroleum Institute, "Quarterly Review of Drilling Statistics for the United States."

APPENDIX C.—*Rates of return*

Industry group	Return on total capital		Return on equity	
	5-year average	Latest 12 mo	5-year average	Latest 12 mo
Automotive	8.3	8.8	10.8	8.9
Aerospace and Defense	7.5	9.2	11.1	11.8
Consumer goods:				
Personal products	12.7	12.6	17.4	16.1
Health care	14.9	13.8	17.3	17.3
Food and drink	9.6	10.2	12.9	14.2
Household	7.3	4.5	9.1	6.0
Textiles and apparel	6.7	4.0	7.9	4.5
Construction:				
Building materials	8.7	8.6	11.2	9.0
Contractor	11.4	16.9	19.6	18.1
Distribution:				
Chemicals	10.1	11.6	14.0	14.8
Retailers	7.6	6.1	11.0	9.8
Supermarkets	7.2	7.6	10.1	10.7
Wholesalers	10.9	11.5	14.1	15.7
Electronics and electronic equipment	9.0	8.1	11.8	12.5
Energy	11.2	11.4	14.9	15.5
International oils	10.9	11.0	13.5	13.1
Other oil and gas	11.0	11.2	14.9	15.5
Coal	15.6	20.6	21.7	28.8
Finance:				
Banks	10.0	10.0	13.4	12.1
Consumer finance	7.0	5.4	12.1	10.6
Insurance	10.4	9.5	11.3	10.4
Forest products and packaging	8.4	8.3	11.3	11.8
Industrial equipment	9.7	10.0	12.4	12.8
Information processing	10.4	9.1	13.7	12.9
Leisure	10.1	8.1	13.5	11.6
Multicompanies:				
Conglomerates	7.6	7.7	11.6	11.7
Multi-industry	7.9	8.4	11.0	10.9
Metals:				
Nonferrous	9.1	6.7	11.4	9.0
Steel	7.7	8.1	10.6	11.7
Transportation:				
Surface	4.8	4.5	6.4	7.1
Airlines	3.5	2.8	5.4	3.9
Utilities:				
Electric and telephone	5.8	5.6	11.6	11.7
Natural gas	7.6	8.0	13.9	13.5

Source: "Forbes," Jan. 1, 1976.

APPENDIX D—STAFF IMPACT ANALYSIS

While the evidence is clear that $1.42/Mcf is a just and reasonable cost-based price, both economics and the law dictate that we also consider the price in relationship to other non-cost factors, including commodity value, economic impacts, and supply-demand equilibrium. The best way to evaluate such factors is in an economic framework.

The approach used here is to simulate the process of shifting the economy to a market-clearing long-run equilibrium, and then to derive the specific characteristics of that shift.

This estimation of the future is necessarily uncertain. It does, however, relate various aspects of the problem to one another with some consistency. Thus we can note that if a higher rate yields a large amount of added gas, the problem of higher costs (from more gas selling at higher rate) is partly offset by the degree to which the added gas displaces a corresponding amount of more expensive alternate fuels. These relative, or differential, effects are frequently more reliable than the absolute magnitudes involved in the estimation; they are also usually the most significant effects.

We begin by making several different estimates of the commodity value of natural gas. We then look at inflation impacts from the transition to such a value, and finally analyze the impacts on producers and consumers.

(1) *Reconciliation With Commodity Value*

(A) BASIC EFFICIENCY ARGUMENTS

An efficient price for a good is the price at which it pays to produce exactly as much of the good as consumers want at that price. In other words, an efficient price for natural gas would induce just enough supply to satisfy consumer demand at that price. If such a price were always reached in the market place, there would be little reason for regulation. However, the market's price is susceptible to two fundamental infirmities, called equity and efficiency distortions, respectively. Equity distortion occurs when the distribution of income and assets is such that the market's price is determined mainly by the preferences of a few. Efficiency distortions arise from many causes, including misinformation, monopoly, and externalities such as environmental costs.

Regulation should attempt to determine a "normative" price, which we may view (and define, for the present purpose) as the price which would be established in a market free of equity and efficiency distortions. For our purpose, the most serious relevant distortions are those which might spring from producer monopoly. It is clear that OPEC is maintaining a monopolistic price for oil, for instance. It is also clear that insofar as the Natural Gas Act assumes potential producer monopoly, this Commission cannot accept intrastate gas prices of the industry as normative. Nor do we. We must, however, consider what such a normative price might be, and determine whether the cost-based rate is also reasonable by that standard.

This does not mean the normative price must be adopted. It may be socially preferable to charge customers a higher or lower price. But any such pricing choice ought to be made with the clearest possible understanding of relevant economic forces.

(B) EQUILIBRIUM OF JURISDICTIONAL GAS

One approach to determining a normative price was the effort of the FPC Task Force on Deregulation, which sought to estimate the price a competitive market might set in the absence of regulation. In its Report,[1] the Task Force estimated that in the case of partial deregulation the 1975 marginal supply price would have been $1.49/Mcf.[2]

While the Task Force found that "a conclusive determination and quantification of the impacts has not as yet been demonstrated," the estimate is still the result of a thorough effort to analyze the process by which the supply and the apparent demand for natural gas could be brought into equilibrium. The estimated marginal supply price, adjusted for inflation, would equate to about $1.65/Mcf today.[3]

The determination was sensitive to a number of assumptions (detailed below) about supply and demand elasticities, future gas demand and availability, and the prices of intrastate gas and alternate fuels. The estimates cited herein are for a case which was

[3] *Ibid.*; this is an average of the range of cases studied by the Task Force.

[2] *Ibid.*, Table 2, Page 5.

[1] Preliminary Evaluation of the Cost of Natural Gas Deregulation, FPC, January 1975.

an average of the range of parametric assumptions used by the Task Force.

This estimate implies that the cost-based price established herein is consistent with a commodity value for gas which would be determined on the basis of the estimated supply, demand, and elasticity relationships within the domestic market for gas.

(C) EQUILIBRIUM WITH INTRASTATE GAS

The regulation of the price of natural gas was based on the premise that workable competition does not exist in the gas-producing industry. If this premise is true, then observed prices in the unregulated markets will be higher than would prevail under competitive conditions. Others contend that in the absence of barriers to entry, production is competitive.

We have been mindful of these opposite views in weighing the price of non-jurisdictional gas as a factor in our price determination.

Intrastate prices have risen dramatically over the past few years, as the prices reported in Exhibit indicate. The most recent average intrastate price is $1.55/Mcf for the first quarter of 1976. Since a competitive market price tends toward the cost of producing the good or service in question, insofar as the intrastate markets are competitive, this price indicates a cost-based price for natural gas. The price we set with this opinion is somewhat lower than this most recent average. The differential may be due to a lack of workable competition in those markets, or a supply/demand imbalance in those markets that results in the current price not being that which would prevail in long run equilibrium.

(D) EQUILIBRIUM IN ENERGY MARKETS

A third approach to determining the normative price is to examine what natural gas price is consistent with world prices for all fuels, still in an equilibrium framework. Several lines of analysis, discussed below, suggest that OPEC is charging a rational monopoly price; that is, a price which is the normative oil price plus a monopolist's rent just sufficient to maximize OPEC profits. That rent is probably under $2/barrel, which suggests that the normative price for oil is about $10.50/barrel, or roughly $1.75/Mcf equivalent.

It is estimated that OPEC production is at about half of its potential level at present, which is consistent with the notion that OPEC is maximizing its monopoly rents. It does not follow, however, that those rents are the entire difference between its pre-embargo price, or its production costs, and the current price. There is another cost component which is often ignored, called "user cost," which is not related to monopoly.

Natural resource economics includes "user cost," the value of a resource in the ground. Prior to 1970, the world tended to feel that only extraction cost mattered, that fuels were infinitely abundant, and worthless until extraction. Recent awareness of resource limits and of environmental quality has changed this view. Energy user costs have become large. Their recognition can account for much of the OPEC price rise.

One way to approximate these "user costs" is to note that environmental control costs have been estimated[4] at roughly $.20 (for 1971) per pound of sulfur emitted, or about $12 for each ton of coal which contains 3% sulfur. The decision to control sulfur emissions effectively added $3 to the worth of a barrel of oil as a substitute for the costs of burning such coal. Adding this value to the 1971 cost of OPEC oil, and adjusting for inflation, gives us a resource value of about $10 for a barrel of oil today. (While domestic sulfur-control policies doubtless were not so fully shifted to OPEC oil, the recent recognition of resource limits must play some role which is not being considered here.)

Historically, gas prices have not matched Btu-parity with oil, but have been 15%–25% lower. This is apparently due to the influence of coal as a ready substitute in many fuel-intensive utility and industry applications where gas is used mainly because it has been so cheap. If we assume gas should be 15% cheaper than oil on a Btu basis, a price of $1.50/Mcf would be implied for a competitive-oil world, and a price of $1.75/Mcf would seem correct if we accept OPEC pricing as part of the real-world alternatives we face. Therefore, in addition to our estimate of a possible market-clearing price, we also note in Exhibits 28 and 29 the actual prices of competitive fuels within the U.S. economy.

To compare these prices, we have taken observed prices of oil in various sectors of the country, and estimated the well-head price for natural gas which would be competitive at the average market. This estimation takes account of the cost of transporting gas from well to the average market, and of the historic energy relationship noted above, with gas selling at about 85% of the Btu-equivalent price of oil.[5]

Exhibit 28 reports prices paid by electric utilities for residual (No. 6) fuel oil over the twelve months ended January 1976, for the major oil-consuming sections of the country. Exhibit 29 uses the most recent spot price data from the Oil and Gas Journal. When the regional prices are weighted by each region's gas consumption we get the following results:

	1,000 ft³ equivalent
Contract No. 6 oil to utilities	$1.43
Spot Market No. 6 oil to utilities	1.28
Recent spot No. 2 distillate	1.57
Recent spot No. 6 residual	1.31

These prices clearly indicate that our cost-based estimate is not far from an equilibrium price with marginal alternate energy sources, at historic price ratios.

(2) *Inflation Impacts*

(A) TYPES OF INFLATION

The Nation is concerned with two kinds of inflation. The first is more obvious, and arises when the money supply expands faster than the supply of goods and services. The second is less obvious, and arises when the economy functions inefficiently, so that the Nation's efforts produce less than they might have. These have sometimes been characterized as demand-pull and cost-push inflation, respectively.

This Commission cannot affect the first kind of inflation. If the price of gas increases while the money supply stays constant, the prices of all other goods and services will decline slightly; there will be no inflation. If just enough new money is printed to pay the extra cost of gas, that money will add to inflation.

The second kind of inflation is produced by any regulatory action which causes the economy to function inefficiently. Some such inefficiencies are desirable at times, mainly for equity reasons. Other inefficiencies arise because the regulatory process often does not keep up with the dynamics of a changing world. The important point to remember is that regulation can produce inefficiencies by setting prices either too high or too low. We will discuss this point in detail below.

(B) EFFECTS OF PRICE CHANGE

In addition to the above kinds of inflation, there is considerable public resistance (especially during periods of general inflation) to specific price increases. If world conditions for a commodity change (as with our environmental awakening, or with formation of OPEC) the value of the commodity will usually also change. In the presence of a stable money supply, the values of all other goods will tend to move in the opposite direction so that there is no general inflation. Even so, the prices which rise will arouse more consumer concern than the prices which decline. This awareness of rising prices should not, however, be confused with concern over inflation. In a dynamic world, it is neither possible nor desirable for government to maintain all prices at some former "status quo" relationship indefinitely, nor even to retard their adaptation, except for clear-cut equity or efficiency reasons.

An equity problem could arise if the price of natural gas rises faster than the consumer can adjust, or when the transition is sharp enough to drive out of business firms which might in time have survived the transition. Inefficiencies could occur if the price change exceeds the proper level, or if the transition creates uncertainty and frictional unemployment in its own right. We discuss both of these possibilities below, under "Demand Impacts." They are not, strictly speaking, inflationary impacts and cannot be analyzed as such.

(C) EFFECTS OF TOO HIGH PRICE

The market price can be "too high" (higher than the normative price) for a number of reasons. The most plausible relevant reason would be on the assumption that gas production is monopolistic, and the Commission sets a price which allows monopoly profits. The process here is that monopolists make the greatest profits when their price is high enough that they sell significantly less of their product than they might sell at competitive prices. When this happens, the consumer loses the benefits of both the added output which would have been available at competitive prices, and also of the consumer surplus which is being captured by the monopolist.

This would mean, for instance, that much of the demand for gas at competitive (or normative) prices would instead seek alternate fuels that would, at competitive gas prices, be less desirable. This means that the economy gets the benefit of less gas than is optimal, it uses more alternate fuel than is optimal, and consumers have less purchasing power than is optimal. The end result is that a given level of national economic activity produces less consumer satisfaction than it would if there were no monopoly.

Monopolies are regulated precisely to avoid this kind of inefficiency. (If equity—the excess profits of monopolies—were the main problem, it could be solved with appropriate taxes.) This kind of inflation is a major and obvious concern.

(D) EFFECTS OF TOO LOW PRICE

Too low a price creates similar, but less obvious, kinds of inflationary inefficiency. If

[4] Cost-Effectiveness of a Uniform National Sulfur Emissions Tax (EPA-600/5-74-009, February 1974).

[5] This relationship was also used by the Canadian National Energy Board in their recent gas pricing decision.

the price is "too low," consumers will use "too much" of the good, and producers will supply "too little" of it. Once again, a given level of national economic activity produces less consumer satisfaction than it otherwise might.

In theory, government can engage in a series of direct allocation, curtailment, and rationing programs to spread the limited supply to the appropriate recipients. In fact, any such program is very limited, especially in light of its poor response to the dynamics of a changing world. Every imperfection means that some of the underpriced good is wasted (rather than correctly husbanded) by someone who undervalues it, while someone who values it more highly must buy a more expensive alternate good—and, in the process, bid up the price of that alternate even higher.

Though this kind of indirect effect from under-pricing is less obvious, it is becoming more widely perceived to be a real cost of regulatory activity. While the Commission has no direct mandate to include inflationary effects as part of our rate-making, it seems clear that setting the price as close as possible to that which would result from a competitive model (normative price) would minimize the total inflationary impact.

(3) *Supply impacts*

(A) RETURN ON PRESENT PRICE

The DCF methodology used in determining the cost-based price also shows that the current 699–H price of $.52/Mcf is sufficient to yield only about 3% return on current-period costs of production. The yield is this low because of methodological shortcomings in 699–H, major increases in tax liability as a result of the removal of percentage depletion, and increased demand for gas as a substitute (given its low price) for hard-to-clean coal and expensive oil. (While OPEC should not be determinant of U.S. fuel price, it is clear that when a substitute for gas becomes expensive, gas becomes more valuable—the proper dynamic response of the market to such a situation is to expand gas production more expensively.)

On close scrutiny, it seems that the 699–H rate allows only about 2% return for on-shore gas, where increased drilling (even at low productivity) reflects the high prices this gas can command in the intrastate market. At the same time, the rate allows a return of only about 5% for off-shore gas. Here, drilling activity has declined, presumably since such gas sells under the 699–H ceiling and is not profitable enough to attract new risk capital. The end result is that the Nation's average gas productivity is declining. This is a specific illustration of the way a low price leads to a more costly result.

(B) EFFECTS OF TOO HIGH PRICE

If the rate is set higher than the normative price, and if gas production is competitive, new gas will be sold for less than the ceiling rate (i.e., at the normative price). If production is sufficiently monopolistic, the rate will allow excess profits to producers as a class. In any event, profits will be highest for off-shore gas. This Commission expects Federal leasing policies to be able to capture some or all of the extra off-shore profits, which seems to constitute a more equitable treatment of the National benefits of gas than a simple distribution, through lower prices, to consumers (mainly industry) who happen to have access to gas supplies. It is also possible that these extra profits will be eroded by expansion of production until it is less profitable. At worst, gas production will be suboptimal and gas producers will receive rents which are only partly captured by income

(C) EFFECTS OF TOO LOW PRICE

If the rate is set lower than the normative price, there will still be a higher profit on off-shore gas, and added (though sub-optimal) quantities will flow to the interstate market. On-shore production would earn a lower yield, and would therefore try to command a yet higher price in the intrastate market. While some on-shore gas would surely move interstate, there would remain some shortage.

(4) *Demand impacts*

(A) SHORT-RUN PRICE IMPACTS

The main impact on consumers from the new national rate will be the added assurance of gas supply. Based on our understanding of current gas supply prospects, we would hesitate to predict that higher prices will reverse the downtrend of gas production that has been experienced during the past few years—we note, for example, that marketed production in the first quarter of 1976 was 2.8 percent lower than a year earlier and that domestic sales to interstate pipelines were 4.3 percent lower.[6] Nevertheless, we are confident that the supply situation would deteriorate more rapidly, especially in the interstate market, if prices were not allowed to increase. The consequence of such deterioration would be the further shift of energy use to higher-priced alternate fuels, notably oil imported from the Middle East. The increased availability of incremental gas supplies at the national rate we have prescribed will be a less expensive alternative for the Nation's consumers.

It should also be noted that natural gas has been supplying almost 50 percent of the energy consumed by the industrial sector of the economy.[7] The availability of increased gas supplies to the industrial sector, particularly where gas cannot efficiently be replaced with other fuels, will contribute to increased productivity and a growing national economy.

These direct and indirect benefits to consumers cannot be achieved at the currently prevailing level of natural gas prices. There is a short-run cost attached to the benefits, a cost that will be determined by the gas volumes that will receive the national rate.

The volume of new supply that will become available to the interstate market at the new gas rate can only be conjectured.[8] It is estimated that on April 1, 1976, gas flowing under 699–H rates exclusive of rollover contracts amounted to 850 Bcf/year from the 1973–74 biennium, and 750 Bcf/year from the current biennium. We will assume that a total of 1750 Bcf is now flowing under 699–H, and that an additional 600 Bcf/year will flow by the end of the coming year.

All 699–H gas now averages about 55.6 cents/Mcf (including gathering allowance and state taxes.) In the next year consumers will pay approximately $1.07/Mcf for 850 Tcf from the 1973–74 biennium, and from $1.50 to $1.53/Mcf for escalating gas (with an estimated annual flow rate of 900 Tcf in the coming quarter, increasing to an annual rate of 1350 Tcf in the last quarter) under the new rate for the current biennium. The total extra cost (versus the 699–H rate) will be about $1.52 billion. This cost, spread over the 11.6 Tcf of interstate volume in 1975, would add 13 cents to the average price paid by the interstate pipelines. The average residential gas customer in the United States consumed 120 Mcf in 1974; a price increase of 13 cents/Mcf would add about $15.60 to the annual bill. The added cost to residential customers in various parts of the country will, of course, vary with their gas consumption. Some illustrative cases based on the above estimate of average-price increase are shown below:

State	Average residential consumption per customer (1974, gas facts) (thousand cubic feet)	Estimated increase in annual bills
Ohio	178	$23.14
Illinois	165	21.45
Pennsylvania	137	17.81
California	101	10.40
New York	90	11.70
Florida	40	5.20

We can also compare the price of gas with its old price, with the general consumer price index, and with oil and electricity prices. We do this with the aid of the latest BLS estimates,[9] for May, 1976 for several representative cities. We start with the May 1976 price from BLS. Then we show the new price, by adding the above 13 cents per Mcf. Then we show the percentage increase in residential gas price for that city. This is followed by an estimate of the change in the average residential bill. Next we show an estimate of each city's revised gas-price index (from BLS Table 4; 1967=100, Maq 1976 CPI=69.2). Next we show the constant-dollar increase in gas price since 1967; that is, the degree to which gas prices have out-run general inflation. Finally we show the ratio of the new gas price to the heating oil price and electricity price on a per-Btu basis.

Exhibit 30 shows that of the 108 cent per Mcf rate increase from 699–H, 44 cents goes to direct taxes, 17 cents goes to royalties, 22 cents goes to cover higher investment costs, and 21 cents goes to producer profits. Of the increase on vintaged 1973–1974 gas, about 35 cents goes to taxes, and less than 20 cents to costs and net profits. Of the entire first-year

	Washington	Boston	Chicago	San Francisco
Average price, May 1976	2.45	3.24	1.87	1.54
New price	2.58	3.37	2.00	1.67
Percent increase	5.3	4.0	6.9	7.8
1974 consumption	95	89	165	101
Bill at May 1976 price	232.75	288.36	308.55	155.54
Bill at new price	245.10	299.93	330.00	168.67
Increase in bill	12.35	11.57	21.45	13.13
New index (1967=100)	189.7	203.5	193.3	229.0
Real price rise since 1967 (percent)	12.1	20.8	14.2	35.3
Ratio to oil price	.84	1.11	.72	.56
Ratio to electric price	.21	.23	.16	.18

[6] Source: U.S. Bureau of Mines and FPC Form 11.

[7] Data from U.S. Bureau of Mines, as published in 1974 Gas Facts, American Gas Association, page 58.

[8] "With * * * (the) many variables, it is impossible, with any degree of precision likely to satisfy the momentary opponent's fetish for quantification, to determine the likely quantitative effect on supply of a chance in rate ceiling." *Placid Oil Co., et al. v. F.P.C.*, 483 F. 2d 880, 901 (5th Cir. 1973).

[9] Retail Prices and Indexes of Fuels and Utilities Residential Usage, May 1976; Bureau of Labor Statistics, 7/76.

cost of $1.5 billion, producer costs will claim about $400 million, tax liabilities will claim $820 million, and producers will receive $280 million in net income.

(B) FUTURE CONSUMPTION TRENDS

Neither the letter nor the spirit of the Natural Gas Act binds the Commission to be concerned only with the welfare of consumers who are presently using natural gas. This fact is obvious, yet it is often overlooked. For instance, a recent study by the Congressional Research Service [10] characterized the possible production of more gas as a "cost to consumers", overlooking the fact that purchasers of such gas would buy it only if it were cheaper than their alternatives.

For analytic purposes, we consider consumers in several classes. Direct consumers of gas are divided into residential, industry, and utility sectors. Potential consumers of gas are divided into the same sectors, and include all consumers who do not presently have access to gas, but who would choose gas if it were available at an equilibrium price. All costs incurred by the utility and industry sectors (whether for more expensive gas, or for curtailments and yet more expensive alternate fuels) are viewed as indirect costs to the population as a whole.

In the discussion which follows, we will focus on the 1980 demand situation for gas at various prices, with explicit consideration for newly cost-effective conservation, and for those gas users who may not be able to get the gas they want. Such consumers must buy a higher-cost alternate fuel to meet their needs, putting added upward pressure on the price of that alternate fuel.

It has been estimated [11] that the national welfare gain from all cost-effective conservation measures would be about $9 billion in 1980. Present natural gas consumers account for a disproportionate share of the costs of energy waste, in large measure because their gas has been so cheap. The analysis which follows takes account of the significant degree of conservation which is possible in each sector if consumers take those efficiency-improving steps that did not pay for themselves at old prices, but do pay in saving the higher-priced gas (even at the rolled-in price).

In the Deregulation Task Force Report, supra, it was estimated that in 1980 gas production would lie between 22.6 and 24.9 Tcf if this Commission adhered to pricing strategies which led, respectively, to level production or level reserve additions. In the "Worst Case" estimate (shown in Table H-16) it was assumed that elasticities were relatively low and demand high; in the "Best Case" estimate (Table H-61) elasticity was assumed higher and total demand lower. These cases implied 8.2 and 1.4 Tcf of unsatisfied demand, respectively.

The characteristics of the average demand and supply projections for 1980 were as follows:

Sector	Total demand	Met by gas	Curtailed
Residential	8.66	7.62	1.04
Industrial	14.78	12.46	2.32
Utility	5.16	3.70	1.46
Total	28.60	23.78	4.82

[10] Economic Impact of S. 2310's Pricing Provisions, 12/22/75.

[11] "Economic Benefits of Energy Conservation", Proceedings of U. of Miami/ERDA Forum on Energy Conservation, December 1975.

There is no present or planned direct curtailment of gas delivery to residential consumers; but we must remain aware of the growing number of new homes for which no new gas connections are permitted. For many of these, the alternative is electricity, even for their heating needs. This alternative is far more expensive to the economy than gas itself, for it requires more primary input energy plus more capital for the generation system.

The model works by estimating the way a changed price for new gas (and expiring contracts) will stimulate supply, and will lower demand by raising the rolled-in price of all gas, so that all the potential demand is satisfied. It is assumed that the alternate fuel would ultimately be supplied from imports, and we estimate the national cost of imports by the first-round taxes which would be paid by domestic producers of the same fuels.

(C) LONG-RUN PRICE IMPACTS

To estimate long-run impacts of this opinion on various consumers, we will deal with the effects of a normative price determined within the gas market. As we noted above, the Task Force addressed this question in asking what price would bring equilibrium between gas supply and demand. In effect we will use that analysis to study the equity effects of shifting toward the efficient price. (This does not imply deregulation, of course—the analysis determines the price which would be reached by a competitive market for gas, while the Commission sets a ceiling price which potential monopolists may not exceed.) We begin by returning to the "Worst" and "Best" demand gaps.

The prices which closed the demand gaps (in 1974 dollars, as the well-head price for new gas, expiring contracts, and intrastate gas) were $1.91/Mcf and $.78/Mcf, respectively; the demand gaps were closed by only 2.02 and .38 Tcf of new gas, plus greater (6.2 and 1.0 Tcf) cost-effective conservation by all the consumers of existing gas.

Since the Task Force analysis seems to be the only model that considers specific classes of present and potential consumer, we will use its results to describe the impact of the current opinion. The two extreme cases have an average well-head price for marginal gas of $1.81/Mcf in 1980 ($1.35 measured in 1974 dollars, adjusted for 5% annual inflation), which is compatible with a 1976 price of $1.65/Mcf plus $.04 annual escalation.

Below we list some of the relevant attributes of the average of these two cases:

Added gas volume due to higher price (trillion cubic feet)	1.20
Saved gas equivalent of alternate fuels (trillion cubic feet)	4.80
Increased revenues of gas producers (barrel)	$9.88
Decreased revenues (e.g., of imports) (barrel)	7.79
Net increase in consumer outlays (barrel)	2.09
Increased outlays by consuming sector:	
Status-quo residential consumers (barrel)	1.45
"Curtailed" residential consumers (barrel)	−.81
All residential consumers (barrel)	.63
Status-quo industrial and utility (barrel)	2.95
Curtailed industrial and utility (barrel)	−1.49
All non-residential consumers (barrel)	1.46

This Table means that the direct outlays, by residential consumers of gas, will rise by $.63 billion; an increase of $1.45 billion to present ("Status-Quo") consumers will be partially offset by a saving of $0.81 billion on the part of consumers who otherwise wouldn't have access to gas. While this change has equity or redistributional aspects, it should be remembered that consumers who already have gas (and will therefore be hurt) have had the historic benefit of a significant subsidy in this low-priced valuable fuel.

The indirect costs to consumers are the added outlays by industry and utilities for gas, minus the national benefits from a reduced reliance on imports. Of the indirect price impact of $1.46 billion, only $0.10 billion is paid through utilities; at the higher price for existing gas, the utilities would lower their total demand (e.g., by load management techniques) enough that their fuel outlays would rise only a little. The remaining $1.36 billion is the added outlay for fuel by industry, all of which must be absorbed by consumers of the industrial products.

We next examine the size and incidence of the costs. First, the costs are not multiplicative—only during monetary inflation (if then) can a producer raise his product cost by 10% because his fuel bill went up 10%. (Some such behavior underlies the idea of "ripple effects".) For a price realignment which reflects true resource costs, there is every reason to think that there is a simple dollar-for-dollar pass through. For instance, in 1971 "Food Processing" used about 5% of industry's natural gas. In addition, "Chemicals" used another 27%, but since only 4% of "Chemicals" gas goes to "Agricultural Chemicals", Food absorbs another 1% of industry's burden by this route. In total, consumers appear to pay only 6% of the $1.36 billion (or about $80 million) extra for their food. This $80 million adds about 0.05 percent to food costs.

Second, the costs are not distributed regressively, at least in the sense that a large fraction of the indirect costs fall on the poor, or on essential products. It has been shown that direct fuel cost is slightly regressive, indirect fuel cost is slightly progressive, and total fuel cost is approximately neutral.

To consider taxes, we note that the above values were derived by averaging Tables H-16 and H-61 of the Preliminary Task Force Report. The assumptions meant that some 13.15 Tcf of total production in 1980 would increase an average of $.63/Mcf from the so-called Status-Quo prices; in addition, there would be 1.2 Tcf of added gas at $1.35/Mcf (in 1974 dollars). Producers would have incremental revenues of $8.26 billion on the former, and an earned income of $1.62 billion on the latter. If we assume (as seems likely) that the former income would be taxable at 48%, and the latter at an average rate of 10%, the total tax receipts would be about $4.1 billion, roughly double the increased consumer outlays. If the alternate fuels ultimately come from imports, and the imports are displaced by conservation and new supply, these tax receipts represent a net gain to the economy. (They are an indirect gain to the consumer for exactly the same reason that industry outlays are an indirect consumer cost.)

The aggregate effect, as best we can predict it, would be that by 1980 consumers will be paying a total of $.63 billion more (than in the "Status-Quo" case) in direct purchases of gas; they will also be paying an indirect amount of $1.46 billion extra for gas through the commodities they buy; but they will also receive the indirect benefit (in the form of a lower tax burden than otherwise) of $4.1 billion in taxes paid by producers from income which goes to domestic, rather than foreign, producers. Thus, the total effect of shifting from the "Status Quo" price to the norma-

tive price would be a benefit of $2.0 billion ($4.1–$0.63–$1.46)—the benefit of removing the inefficiency associated with the present underpricing of natural gas.

(D) EFFECT OF TOO HIGH PRICE

The notion of "too high" a price can be represented in two related ways. We can either ask what happens if a price higher than the normative price is used as a ceiling, or we can ask what happens if the normative price itself is lower. The latter case can arise only if the real-world situation is "better" than the "average case"; in which situation we would have larger supplies, lower demand, and less import reliance than was modeled. If gas production is competitive, the lower normative price will prevail, and consumers will be better off. Otherwise, consumer costs are higher, and the added costs are only partly recovered by taxes on producers.

Specifically, if producers charge monopolist prices at a ceiling rate that is too high, the net cost of each 1-cent error in setting the rate is roughly $10 million. A 5-cent error would mean that consumers would pay an extra $100 million, of which about $48 million would be recovered in marginal taxes on the producers.

(E) EFFECTS OF TOO LOW PRICE

On the other hand, "too low" a price can be represented by a world in which demand is greater, supplies are lower, and imports are higher. In this case, we clearly have an element of additional "excess" demand which can be supplied only from alternate fuels at a higher price than that allowed for gas. In this case, consumer costs are higher by the extra cost of the alternate fuel, plus whatever national cost is attributed to the added reliance on foreign fuel supplies.

An error in the direction of too low a price ought also to have a net cost of about $10 million for each one-cent error. In this case, a price 5 cents too low should lead to present consumers of gas saving about $30 million, while other consumers would be forced to spend about $80 million more on the purchase of alternate fuels.

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